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ONSHORE IMPACTS OF OIL AND GAS DEVELOPMENT IN ALASKA. VOLUME II. METHODOLOGY APPENDICES

Resource Planning Associates

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ONSHORE IMPACTS OF
OIL AND GAS DEVELOPMENT
IN ALASKA
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DEVELOPMENT ASSUMPTIONS

In keeping with the "what if" nature of this study, we postulated the economic and environmental impacts of oil and gas development in Alaska from a series of assumptions. Although firm data are restricted to some rather limited and debatable reserve estimates and the results of Alaska petroleum development to date, we believe that these assumptions about oil/gas developments, secondary effects, and consequent impacts are representative of what could happen.

Future events will depend on actual decisions now being made at state and national levels and of the actual presence - or absence - of commercially attractive deposits. There is no guarantee that our speculative assumptions and the development scenarios derived from them will reflect these events. However, this does not invalidate them. The methodology we adopted to formulate the assumptions is reasonable and realistic in the light of the available data. The following description of the methodology should serve to substantiate the assumptions.

A - METHODOLOGY USED TO FORMULATE THE DEVELOPMENT ASSUMPTIONS

The methodology used involved a number of steps. First we analyzed a general model of oil and gas development, visualized in Exhibit A-1, to identify the essential components of such a development. Each of these components was then defined. At the next step, we used the definitions as the basis for making a series of assumptions that were essentially a set of parameters of the components. Next, we selected an appropriate set of assumptions that mapped the model onto each individual area of the study to yield a development alternative. Finally, the development alternatives were ranked cumulatively in order of likelihood to formulate the scenarios.

In the following section, we define the components of the oil and gas development model.

DEFINITIONS OF THE COMPONENTS OF THE OIL AND GAS DEVELOPMENT MODEL

We identified eight basic model components: leasing, exploration, discovery, delineation, development, production, transportation, and related facilities.

Leasing

Exploration by drilling cannot begin until acreage has been leased.* The date of the lease sale then will be one important determinant of how quickly an area will be explored. The type of lessor will affect the speed of development. In Alaska, the major lessors are the federal government (i.e., the Department of the Interior), the State of Alaska, and the native associations. Each has different objectives, and competes with the others for industry funds. Each has a different impact on the flow of money into Alaska, with proportionately more money remaining in the state if the lands leased are native- or state-owned.

Exploration

The extent of exploration will depend on a number of factors:

1. Level of leasing activity. Historically, rig mobilization is greatest prior to and shortly after a lease sale.

2. Cost per well. In northern Alaska, for example, an exploratory onshore well of 10,000 feet costs approximately $7 million. In the Lower 48, the cost of a similar well is only 1/3 to 1/5 as much. Thus, an oil company can drill 3-5 wells in the Lower 48 for the same price as one well in northern Alaska.

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* Except for stratigraphic wells drilled only to determine the types of rock in the area.

3. Rate of discovery. A discovery in an exploratory area tends to increase the level of future exploration in that area.

4. The size of the exploratory area. A geographically large area will require more wells than a geographically small area to evaluate fully the area's potential.

5. The length of the drilling season. Areas, such as the North Slope, with short exploratory drilling seasons will require more rigs for the same level of exploration than areas where weather permits year-round drilling.

6. Availability of equipment/facilities. Availability of drilling rigs, tubular goods, and other materials required for oil and gas exploration and development will affect the level of exploration. At present, there is a worldwide shortage of equipment.

7. The development of drilling technology. A sophisticated drilling technology will obviously accelerate exploration. The present state of the art, for example, does not allow exploration and development of such areas as the Chukchi Sea at this time.

8. Cost of oil. The ultimate decision as to whether to proceed with development will of course depend on the expected cost of producing oil, its delivered price to market, and the world price for oil.

Discovery

The rate of discovery depends on whether industry explores the most promising prospects first (resulting, presumably, in early discoveries), which in turn depends on how quickly knowledge of the petroleum geology of the area is acquired.

The number of discoveries depends on the discovery experience in the region and on the size of the total discovery necessary for lucrative commercial production. On the North Slope, for example, discoveries were classed as Prudhoe size (i.e., 6-10 billion barrels), Kuparuk or Lisburne size (i.e., 1-2 billion barrels), or intermediate size (100-500 million barrels), with the proviso that a discovery could be made up cumulatively of several smaller discoveries close enough together to justify the expense of production and tanker facilities.

Delineation

After a discovery has been made, it usually takes several years to build platforms and support facilities, and to plan development and production facilities. During this predevelopment period, the field area is delineated by drilling 2-10 wells. The cost of each of these delineation wells is estimated at two-thirds of the cost of an exploratory well, since knowledge of the stratigraphy, formation pressures, and depth to the pay zone (derived from exploratory wells) allows rapid drilling and precludes drilling beyond the pay zone.

Development

Development is dependent on the number of development wells in a delineated field and their spacing.

Development time is determined by estimating the time necessary to prepare production facilities (approximately 3 years for the construction of a platform, 2-3 years to develop a production well) and the rate of decline of a field before waterflood becomes necessary. At least one-half of the development wells may be drilled before full production is achieved.

Production

Production depends on the number of wells producing, the rate at which each well produces, the rate of decline of each well, and the life of the field. The typical production cycle for a field consists of three stages: initial production; build-up to a maximum production rate as more wells are brought into production; and decline.

Gas production is different from oil production in that it declines at a much slower rate, and no secondary recovery is assumed for gas.

The lag time between discoveries, development, and production tends to stretch out the useful life of pipeline and transport facilities and requires a smaller capacity for these facilities than if all discoveries were brought into production at the same time.

Transportation and Related Facilities

Integral to oil and gas development are the facilities required to transport production to market. These facilities include pipelines, gas processing facilities, terminals for oil and gas, airfields, living quarters, and storage facilities.

SPECIFICATION OF THE ASSUMPTIONS

Although the development alternatives, and the scenarios constructed from them are speculative, the assumptions behind them were clearly specified and based on the most recent data available.

In this section, the development assumptions are specified under the headings identifying the eight model components to which they apply. Under each heading, the supporting data, where available, are given.

Reserves Estimate

The USGS potentials, delineated in Geological Circular 725, were used for the development areas. These estimates are much lower than the earlier estimates published both by the USGS and by the State of Alaska. However, they were used in the study because they were derived through a more thorough geological and statistical formula than previous estimates. The estimates derived by the USGS employ probabilities. For the purpose of this study, the mean probability was selected for each area as representing the most realistic estimate. In cases where the potential was not already subdivided to the individual areas, it was allocated among the areas after consultation with USGS and industry geologists. The potentials used are shown in Exhibit A-2.

Leasing Schedule

The assumed leasing schedules generally followed the leasing schedule published by the Department of the Interior in November, 1974.* This schedule has since come under criticism as being too rapid to allow efficient exploration. Where possible, the assumed schedule was modified to reflect this concern. It was also staggered to allow for the preparation of environmental impact statements. On the whole, however, no great delays were assumed. The result is that our schedules for the remaining components probably reflect the most rapid development possible, leading of course to larger impacts than under a more extended schedule.

Exploration

The extent of exploration in an area was assumed to depend on rig availability, industry knowledge of the area, cost of individual wells, and potential. In areas of low potential, fewer exploratory wells were judged necessary for evaluation than in areas of high potential. Furthermore, in areas where the cost of an exploratory well is high, an oil company is assumed to be more likely to become discouraged and abandon exploration efforts. It was also assumed that the rate of leasing would be geared to orderly exploration and evaluation of the potential of an area. The equipment shortage was assumed to be short-lived and was not considered as a limiting factor in the development scenarios. Finally, development of more sophisticated technologies was assumed to keep pace with the chronological development of the scenarios.

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* This schedule was used because the first phase of our study (the design of the assumptions) was completed prior to the publication of the June, 1975, schedule.

Discovery

The discovery rate for a region was based on industry interest, proximity to known oil and gas reserves, industry knowledge of the area (presence of large structures, oil seeps, seismic data), leasing schedule, and rig availability. It was generally assumed that areas placed early in the leasing schedule would be areas with the highest potential discovery rate. In general, exploration was assumed to result in discovery which would occur within 2-3 years of commencement of exploration. Most of the potential of an area would be discovered within 15 years of that date. As the high cost of drilling and development requires a large discovery to be economical, a finding rate, based on a wells/discoveries ratio, was impossible to estimate without a more detailed analysis and more data than were available. Also, as more knowledge of Alaskan oil and gas geology is accumulated during the early stages of exploration, the finding rate of the areas placed later in the schedule (such as the Chukchi Sea) would change.

Key determinants in selecting a discovery size were: the total potential of an area; industry knowledge of the size and number of structures in an area; a basic estimate of the minimum-size field necessary for commercial development; and an assumption that the potential of an area is the commercial potential. This last assumption must be qualified, since the USGS estimates used for potential do not emphasize economic analysis. The economic potential of an area may be lower than the estimate derived by the USGS.

The minimum-size field for an area was based on information from industry sources and some very crude economic analyses. For example, it was generally felt that the minimum-size field for the Gulf of Alaska would be 300-500 million barrels. However, this total could consist of several smaller fields in sufficient proximity to allow a central gathering and transportation facility to serve them all. In addition, a field discovered in the vicinity of a developed field would probably have a smaller minimum size, as transportation and supply facilities would be available at little incremental cost. For example, the cost of developing a small field (100 million barrels) within 25 miles of Prudhoe Bay would be much less than developing an equivalent field in NPR-4. However, if large production were developed in NPR-4, a nearby small field might be economic.

Delineation

Up to 10 delineation wells were assumed for each discovery. As the minimum-size field in most cases is at least 200 million barrels, the area covered by the field (assuming a mean pay zone of 100 feet and a recovery of 200 barrels per acre-foot) is 10,000 acres. At least one delineation well would be necessary to confirm the discovery. In addition, up to 9 wells were assumed to determine the boundaries of the field. The number of wells necessary was proportioned according to the area of the field. Twenty percent of the wells for each field were assumed to be dry. The remaining wells could be used either for production, secondary recovery, or disposal purposes.

Development

Major assumptions were made with regard to spacing, timing, and platform characteristics. Any assumption made on timing is highly speculative. The delays in Alaskan North Slope (environmental cause) and North Sea (technical and resource shortage) illustrate the tendency for long lag-times between leasing and production. Once production had begun, however, it was assumed that these delays would be minimal, and that production will be efficient and steady. In general, it was assumed that minimum time for offshore development to begin, following a discovery, was 3 years. This allows time for delineation, utilization proceedings, the filing of environmental impact statements, and the installation of the initial platform.

A 320-acre spacing was chosen for development drilling. The spacing decision is normally made after extensive reservoir analysis. In most areas, there was little or no reservoir data, as no wells have been drilled. The 320-acre spacing affords the greatest flexibility in the absence of firm data. It would allow for waterflood, and provides uniformity between the alternatives.

It was assumed that 16 wells would be drilled from each offshore platform and 8-16 wells from an onshore pad. Again, this decision would be made after extensive analysis in an actual development situation. Estimates from other sources range from 10 to 30 wells. The Gulf of Alaska Operators' estimate of 16 wells was chosen because it appeared to be a reasonable estimate in uncertain circumstances.

Production

Production timing, decline rates, and production rates were determined from available data from developed Alaskan fields, industry estimates, and economic parameters. The 2,000 BOPD estimate for the Gulf of Alaska, for example, was made by comparing production rates for Cook Inlet oil fields. It was also felt that 2,000 BOPD was the minimum economic production level for development wells that may cost over $2 million each. A 14-16-year well-life was derived from the industry-accepted 20-year time frame, allowing for the accelerated production rate made necessary by the high costs of development/production and the high demand.

It was assumed that a well would produce at a high rate for 3 years, then decline rapidly. Waterflood was assumed to start at that point and continue for up to 10 years. After this the field would undergo an accelerated decline (25 percent per year) due to "breakthrough" of water. This was assumed both to simplify the production assumptions (since the well could then be assumed to produce at a steady rate) and to allow for maximum development of the field. Also, it was felt that the high cost of development would make maximum recovery of in-place reserves essential if a field was to be economical. Without knowing the reservoir conditions, waterflood appeared to be a realistic choice. Furthermore, waterflood is either in progress or contemplated for the oil fields now in production or under development in Alaska.

The number of operating wells for a given field was determined by employing a simplifying assumption: a well brought into production was considered to produce for 12-14 years, at which point it would be taken out of production. This is somewhat unrealistic: wells on the periphery of the field are likely to go out of production first, while wells in the main area of the field are likely to continue production, even if at reduced rates, for the life of the field. The main field area wells would normally be drilled and produced first; however, as there is no simple way of predicting a development pattern, the above assumption was employed. Furthermore, as the minimum production rate for a field is impossible to predict without detailed reservoir and economic data, a field was considered to go out of production when its assigned potential had been reached. Its decline rate was generally set to allow production of its potential within the field life. For example, a field in the Gulf of Alaska would be capable of producing 18,000 BOPD in the 17th year. However, if production had totaled 504 million barrels over 16 years - the assumed potential for the field over its life - the field was shut down in the 17th year, regardless of whether or not it would still in fact be economical to operate it.

Transportation and Related Facilities

For each one of the development alternatives, we have assumed a likely development area and the likely timing and magnitude for each step in the development process. We have also made assumptions describing the timing, size, and location of processing and transportation facilities to move Alaskan oil and gas to markets outside the state. The facilities considered were pipelines, crude terminals, gas processing facilities, liquefaction plants, and gas terminals.

We have generally followed a pattern in estimating the likely facilities. First, where it appeared feasible, offshore tanker loading was assumed for the transport of crude oil. In the North Sea, this has proven to be the most economical method of on-loading crude, and minimizes onshore environmental impact. (However, it is not clear that offshore loading could be used in Alaska, and, if the transportation decision had to be made today, offshore loading would not be the preferred approach.) Second, we assumed that, because of the large facilities required, natural gas would usually be liquefied onshore for transport to the Lower 48 via LNG tankers.* Third, we have assumed that, where feasible and necessary, additional oil and gas pipelines would be built in the Alyeska utility corridor rather than along a new route.

We further assumed that no refineries** or petrochemical complexes would be attracted to Alaska in response to the availability of oil and gas. The high cost of construction and operation, limited suitable land, and the high environmental impact of these facilities make their construction unlikely.

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* In the case of Prudhoe natural gas, two competing transportation schemes are before the FPC. One seeks to transport natural gas across the North Slope, through Canada, and then to Lower 48 markets. The second seeks to use generally the same utility corridor as the Alyeska oil pipeline. Gas would be liquefied at Gravina Point for shipment. Without expressing a preference, we have included the latter proposal in our scenarios in the belief that its impacts on Alaska would be greater and subsequently more interesting for analysis. However, we have included a separate summary of the impacts of the former project.

** Apart from those necessary to serve local needs.

B - ASSUMPTIONS USED IN DEVELOPMENT SCENARIOS

For each development scenario, we selected the major assumptions that reflect the eight components of the oil and gas development model for the area under consideration.

Although the validity of the assumptions varies widely from one scenario to another depending on the knowledge and information available for each area, we have tried to make reasonable "what-if" assumptions. The major assumption is, of course, that oil and/or gas will be produced under each of the scenarios.

For convenience, the descriptions are condensed under various headings including: General Assumptions (leasing and discovery assumptions); Exploration Assumptions; Development Assumptions; Production Assumptions; and Transportation and Related Facilities Assumptions.

PRUDHOE BAY OIL AND COOK INLET (BASE CASE)

The base case included major oil and gas activity in Alaska either in progress or virtually certain to develop. Hence, the base case reflects current activities in Cook Inlet and the production and transportation of Prudhoe Bay oil from the Sadlerochit Reservoir only.

General Assumptions

Following discovery in 1968, onshore exploratory oil drilling has been in progress at Prudhoe Bay for several years. Current development drilling is not expected to lead to major oil production until late 1977, when the Alyeska pipeline should be ready for operation. No commercial gas production, other than that needed to fulfill Prudhoe Bay production requirements is expected.* Gas produced from wells will be injected back into the producing zone via gas injection wells to be drilled in 1976.

The published American Petroleum Institute estimate of potential recoverable reserves in the Sadlerochit Reservoir is 9.6 billion barrels.** It is assumed that initial production will be from this reservoir only, using gas drive. A decision on whether to waterflood or not will be made after several years of production. Accelerated production requiring additional development wells to fill the pipeline to its capacity of 2 MMBOPD was not considered.*

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* See Prudhoe Bay Natural Gas development alternative.

** Oil and gas recoverable reserves, initial development date, production schedule, and transportation requirements for each scenario are summarized in Exhibit A-4.

Oil has been produced in Cook Inlet since 1958, with production rising to over 83 million barrels in 1970 and tapering off to 70 million barrels in 1974. Gas has been produced commercially since 1960. All told, there are some 6 oil fields and 21 gas fields in the Cook Inlet area. All oil fields and 8 of the gas fields are currently producing.

We assumed that development in Cook Inlet has been substantially completed.

Exploration and Delineation Assumptions

Exploration of the Sadlerochit Reservoir has been completed. No further exploration or delineation of the field was assumed, although the size of the field may be extended during development.

Development Assumptions

Atlantic Richfield is the only company currently involved in development drilling. It was assumed that 30-45 days are required to drill a development well, with an average depth of 10,000 feet. Development drilling will probably be completed by 1980-1981. The State of Alaska has approved 320-acre spacing for the development drilling. Initial development is confined to an oil column 200 feet in thickness, with later wells moving both upstructure and downstructure of this interval.

Production Assumptions

The rate of Sadlerochit production was assumed to be 8,000 BOPD per well. Production will start in 1977 at 1.2 MMBOPD, rising to 1.6 MMBOPD by 1980. We assumed 150 wells for initial production. Ultimately as many as 500 wells may be drilled.

In Cook Inlet, we would expect oil production to be in the 190,000-195,000 BOPD range until about 1983, declining to about 90,000 BOPD in 1990. We assumed gas production will gradually increase from 400 MMCFGPD to 800 MMCFGPD in 1984 as shut-in gas fields are brought into production.

Transportation and Related Facilities Assumptions

Oil production from Prudhoe Bay cannot be realized until a satisfactory oil transportation network is in operation. It was assumed that the trans-Alaska pipeline will be completed by mid-1977. Right-of-way permits have been granted by both federal and state authorities for the pipeline route from Prudhoe Bay to Valdez. Parallel haul-road construction along the pipeline right-of-way is expected to be completed by mid-1975. However, possible shortages of necessary supplies, e.g., all forms of steel equipment and particularly tubular goods, may postpone completion of the pipeline until after 1977. Construction of a temporary dock has been finished at the Valdez terminal site. The schedule for construction of all transport-related facilities is:

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* Additional production to fill the Alyeska pipeline to full capacity was considered in the Other Prudhoe Private Development scenario.

- Phase I
    - 1974
        - Existing camps upgraded and new camp construction begun (for a total of 33)
        - Road from the Yukon River to Prudhoe Bay completed
        - Clearing of right-of-way for pipeline south of the Yukon River
        - Preparation of pump station sites
        - Beginning of construction of Valdez tanker terminal
    - 1975
        - Laying of pipeline south of the Yukon River
        - Beginning of pump station installation
        - Clearing of right-of-way for pipeline north of the Yukon River
    - 1976
        - Laying of pipeline north of the Yukon River
    - 1977
        - Installation of Pump Stations 1, 3, 4, 8, and 10
        - Pipeline capacity of 1.2 MMBOPD at completion of Phase I

- Phase II
  - 1977-1978
    - Completion of installation of Pump Stations 6, 9, and 12
    - Completion of 2-5 supertanker berths at Valdez
    - Pipeline capacity of 1.6 MMBOPD at completion of Phase II
- Phase III
  - 1978-1979
    - Completion of installation of Pump Stations 2, 5, 7, and 11
    - Pipeline capacity of 2.0 MMBOPD at completion of Phase III

Facilities will include (in addition to the pipeline and its related structures), several airstrips, an operations center for each company (150-225 persons each), gathering centers (flow stations) with 300,000 BOPD capacity each, a small refinery of 6,300 BOPD capacity (presently in operation) to provide fuel for use at the Prudhoe Bay location, and service and drilling company facilities. Exhibit A-5 shows the location of facilities. Exhibits A-6 and A-7 show the production assumptions for the base case.

OTHER PRUDHOE PRIVATE DEVELOPMENT

General Assumptions

The Prudhoe Bay Field and Sadlerochit Reservoir (described in the base case) are estimated to have a production capacity of 1.6 MMBOPD by 1978, assuming the present development plan (according to the Project Independence Blueprint, Oil Task Force Report, Exhibit IV-2). To operate the Trans-Alaska pipeline at its design capacity of 2 MMBOPD, an additional 400,000 BOPD will be needed. Potential sources of this additional oil are the Prudhoe Bay Kuparuk Reservoir, which extends west from the Prudhoe Bay Unit Area; the Prudhoe Lisburne Reservoir, which lies 500 feet beneath the Sadlerochit Reservoir; a shallow, heavy oil accumulation located west of the Prudhoe Bay unit; and other North Slope areas remote from Prudhoe Bay. The potential amount of recoverable oil reserves in the first three areas are estimated at 1.5-2.0 billion barrels, 1.0-2.0 billion barrels, and 200 million of an in-place total of 2 billion barrels, respectively. In addition to oil, the Lisburne formation is estimated to contain 8 trillion cubic feet of gas. At $11.00 per barrel, the heavy oil deposit is not commercially viable, but new technology to make heavy oil production feasible by 1985 was assumed.

Other development on state lands and lands open to native withdrawal appear possible. The potential area extends from the Canning River (Arctic Wildlife Range) in the east to the Colville River (Naval Petroleum Reserve - 4) in the west. Recoverable potential is estimated at 300 million barrels of oil and 2 trillion cubic feet of gas. Gas potential includes the Kavik, Kemik, and Gubik gas fields, which have been discovered but whose total potential is not known.

Exploration Assumptions

No new exploratory drilling is assumed in the Kuparuk and Lisburne fields. We assumed 23 delineation wells to delineate these fields. In the heavy oil area, 10 exploratory wells are likely to be drilled beginning in 1980, followed by 10 delineation wells beginning in 1983. Other North Slope exploration was assumed to require 25 exploration wells, followed by 10 delineation wells. Exploration of this latter area will proceed one year after state and native leasing takes place over the period 1976-1980.

Development and Production Assumptions

Development of the Kuparuk Reservoir is expected to begin in 1978 and to be completed by the end of 1983. Production from the reservoir is expected to reach 400,000 BOPD by 1981, with an average production rate of 2,000 BOPD per well. Approximately 250 development wells, of which half will be water injection wells, will be drilled with 320-acre spacing. Very little gas has been discovered in the Kuparuk Reservoir to date, and no gas development or production is assumed.

The first development wells will be drilled in the Lisburne Reservoir in 1980, and the last by the end of 1984. Initial production from the reservoir is expected to be 450,000 BOPD in 1984, building to a peak of 600,000 BOPD in 1986. At peak production, approximately 200 wells will be producing an average of 3,000 BOPD each. From this peak, reservoir production is expected to decline at about 14 percent per year without secondary recovery. Overall life of the reservoir is estimated at 16 years.

Development at the heavy oil reservoir is likely to begin with the advent of new technology by 1985, and to be concluded by the end of 1988. Initial production was assumed to be 80,000 BOPD in 1988, reaching a peak of 100,000 BOPD in 1989. At maximum production, approximately 200 wells with 320-acre spacing will be producing at a rate of 500 BOPD.

Development is expected to begin on other (onshore private) North Slope areas in 1985 and to be completed by the end of 1992. By 1989, production from these smaller reservoirs is estimated to reach an aggregate of 100,000 BOPD.

Transportation and Related Facilities Assumptions

The development of these additional North Slope reservoirs requires very few additional facilities to supplement the massive Prudhoe Bay development. In Kuparuk, two gathering centers of 200,000 BOPD capacity will probably be needed. Two 300,000 BOPD gathering centers are more likely for the Lisburne Reservoir. Small collection systems are required for the heavy oil and other reservoir production. Small diameter pipes will have to be laid to connect the gathering systems to TAPS.

Looping of the Alyeska pipeline would be required by 1984, with an expansion of Valdez terminal facilities to a 2.3 MMBOPD capacity by 1985.

Exhibit A-8 shows the location of expected pipeline and gathering facilities required. Exhibit A-9 shows the development assumptions for other private development.

PRUDHOE BAY NATURAL GAS - EL PASO

General Assumptions

There is no gas currently being produced from the Prudhoe Bay region, other than the small amount being used by British Petroleum for development of the field. No gas production is assumed under the base case scenario or under the Other Prudhoe Private Development scenario. Gas produced with the oil will be fed into a gas-injection plant to be directed back into the original producing zone until facilities are available for its transportation. Ten gas injection wells will be drilled in 1976 for this purpose.

Two proposals are before the Federal Power Commission to transport North Slope natural gas to the Lower 48: the El Paso proposal, and the Arctic Gas proposal. We arbitrarily selected the El Paso proposal for analysis here, in the belief that its impacts in Alaska would be substantially greater.

The El Paso Alaska Company, a subsidiary of El Paso Natural Gas Company, has estimated in-place gas reserves at Prudhoe Bay to be 13.4

trillion cubic feet of solution gas and 21.7 trillion cubic feet of associated gas. Recoverable reserves are estimated to be in excess of 27-29.2 trillion cubic feet over a 25-year period. This development alternative assumed that the El Paso Alaska Company will be able to render transportation service to "parties" who may own or control Alaskan gas in the Prudhoe Bay region. The El Paso Trans-Alaska Gas Project will include a gas pipeline system, a liquefied natural gas plant, a marine terminal, and a liquefied natural gas carrier fleet.

Exploration and Development Assumptions

It is expected that exploration and development for gas, already initiated in Prudhoe Bay in conjunction with oil exploration and development, will continue until the pipeline is ready to operate. An initial 800 MMCFGPD of solution gas will be produced from oil wells for 3 years prior to the start-up of the pipeline system. For this development alternative, we assumed 640-acre development spacing.

Production Assumptions

It was assumed that Federal Power Commission approval will be granted to the El Paso pipeline project by 1976; that accelerated construction activity will last through 1979; that construction of the compression stations will be completed in 1.5 years; and that the pipeline will be ready to operate by mid-1980.* Gas production during that year is expected to be 2,100 MMCFGPD and gas available to the pipeline is expected to be 1,600 MMCFGPD. The production forecast, for the Sadlerochit field is a gradual builup to 4.1 billion CFGPD in the 20th year of operation, declining to 3.3 billion CFGPD by 2000. This forecast includes gas used for operating equipment t Prudhoe Bay. The maximum volume of gas available to the pipeline is expected to be 3.3 billion CFGPD in 1986, declining to 2.7 billion CFGPD in 2000.

Transportation and Related Facilities Assumptions

Necessary pipeline facilities will include a central gathering center at Prudhoe Bay, 809 miles of 42" pipeline from Prudhoe Bay to Gravina Point on the southeast coast of Alaska, and compressor stations. The gas liquefaction plant will require:

- Eight refrigeration/compression modules of approximately 380 million SCFGPD capacity
- Four 550,000-barrel insulated storage tanks

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* As of late 1975, however, assuming a mid-1976 decision, this schedule seems optimistic.

- Buildings for administration, maintenance, warehousing, process control, and a cafeteria
- Two berths each capable of handling LNG carriers of up to 165,000 cubic meters capacity.

Because we have assumed that the pipeline will carry natural gas beyond that already identified at Sadlerochit, additional compressor stations on the pipeline will be required to expand to at least 5.2 BCFPD by 1989. We assumed this volume will be accommodated by nearly doubling the LNG plant and terminal capacity by that time.

Exhibit A-10-1 shows the assumed location of facilities for this development alternative. Exhibit A-11-1 shows the assumed development pattern.

PRUDHOE BAY NATURAL GAS - ARCTIC

General Assumptions

Although we have arbitrarily selected the El Paso proposal as an alternative in our cumulative scenario analysis, we will consider separately an alternative including development through the completion of the Arctic project.

The Alaskan Arctic Gas Company has estimated proved and salable gas reserves in the Prudhoe Bay area at 22.6 trillion cubic feet: 2.0 trillion cubic feet (associated gas) from the Sag River Area; 12.7 trillion cubic feet (associated gas) and 7.9 trillion cubic feet (solution gas) from Sadlerochit. The Arctic Gas project would entail a 42" pipeline beginning at Prudhoe Bay and consisting of three sections: a 195-mile section running eastward through Alaska to the Canadian border; a second section beginning at the Canadian border and traveling by the MacKenzie River Delta to a branching point near Calgary, Alberta; and a final section starting at the branching point and dividing eventually into three branches to points near Pittsburgh, Los Angeles, and San Francisco. This project does not involve any liquefaction or processing facilities, or a marine transportation system.

Exploration and Development Assumptions

It is expected that exploration and development for gas, already initiated in Prudhoe Bay in conjunction with oil exploration and development, will continue until the pipeline is ready to operate. An initial 800 MMCFGPD of solution gas will be produced from oil wells for 3 years prior to the start-up of the pipeline system. For this development alternative, we assumed 640-acre development spacing.

Production Assumptions

We assumed that approval will be granted to the Alaskan Arctic Gas Company by 1976, and that construction will be initiated in 1977, to be completed by mid-1980. Annual gas delivery during the last six months of that year is estimated at 365 MMCF. Present planning is based upon a flow of 2000 MMCFGPD from the start of operations, increasing through the second full year of operation (1982) to 2250 MMCFGPD. The capacity of the pipeline could be increased to approximately 4500 MMCFGPD with the installation of compressors and refrigeration systems at preselected locations along the pipeline route. No pipeline looping would be required until and unless Alaskan sources furnished over 4500 MMCFGPD.

Transportation and Related Facilities Assumptions

The pipeline system within Alaska would include:

- four maintenance station (potential compressor station) sites
- a measurement station
- two material stockpiles at coastal wharves
- six airstrips
- five primary and four repeater communication sites
- field operating headquarters at Prudhoe Bay.

The total estimated land requirement for the facilities is approximately 900 acres. During the first five years of its operation, 39 persons will be required to maintain the pipeline.

GULF OF ALASKA

General Assumptions

The Gulf of Alaska's potential reserve area encompasses a large offshore section of the Pacific Ocean, stretching from the tip of Kodiak Island north along the coast and then south to the Alexander Archipelago. Both federal and state lease sales are scheduled within this area in the near future. Federal sales are planned by the Department of the Interior for 1975 and 1976. The 1975 sales area extends off Alaska's southern shores seaward from the 3-mile state territorial water boundary out to the 200-mile line, and from the central Prince William Sound area east to Yakutat and down to Cape Fairweather, on a general east-west line north of Juneau. The federal sale scheduled for 1976 will occur in a region east and south of Kodiak Island. A state sale is scheduled for 1977 in the Yakutat Bay region. This development alternative assumed that leasing and exploration will commence according to schedule.

Exploration Assumptions

A stratigraphic test well is presently being drilled in anticipation of a federal lease sale. We have assumed 349 exploratory wells for this development alternative, beginning in 1975 and ending in 1991. The exploration and discovery process will occur in "jumps", i.e., if one field were discovered in an area, exploration would most likely be intensified in that area, with a high probability of discovery of other, smaller fields. Oil discoveries were assumed for 1977, 1979, 1981, 1983, and 1986, with 500 million barrels of oil per discovery. Gas discoveries were assumed to occur in 1978, 1980, 1981, 1982, 1984, and 1985 with 1 trillion cubic feet per discovery. The final trillion cubic feet of gas potential was assumed to be associated with oil production. Delineation wells were expected for each oil field, drilled from rigs similar to those used for exploration.

Development Assumptions

Development was assumed to begin in 1980 and to be completed by 1993. We have assumed 320-acre spacing for development, with 16 wells to a platform. Since we assumed 96 wells will be required to develop each oil field, 6 platforms will be needed per field. It will take 3 years from discovery to construct and install the initial platform. Gas development was assumed to lag oil development by one year, with 32 wells (320-640 acre spacing) being drilled for each of 6 gas fields.

Production Assumptions

Initial oil production was assumed to occur in the third year of development, with full production in the fourth year. When production begins in the Gulf of Alaska, the output is estimated to be 128,000 BOPD. Total production is expected to peak in 1992. Initial production from each well was assumed to be 2,000 BOPD, declining to 1,000 BOPD. When waterflood occurs, 48 wells in each field will be producers, each producing 2,000 BOPD. The normal life for each field is 16 years.

Gas production includes both associated-dissolved gas and non-associated gas. Each oil well was assumed to produce gas at a rate of 2 MMCFGPD. Each gas well produces at 16 MMCFGPD. Thus each oil field has a production capacity of 192 MMCFGPD, and each gas field a production capacity of 320 MMCFGPD.

A total of 1,076 wells were estimated for the Gulf of Alaska region, of which 672 will be production wells (240 water injection).

Transportation and Related Facilities Assumptions

Oil produced in the Gulf of Alaska was assumed to be loaded onto tankers via single point moorings and floating storage systems.

Gas was assumed to be processed and liquefied for shipment to the Lower 48. We further assumed that gas will be produced in approximately equal amounts in three areas: offshore Yakutat; the Hinchinbrook Island/ Middleton Island area; and near Kodiak Island. The gas would be processed and liquefied for shipment onshore at Yakutat, Cape Junken, and Kodiak Island.

As exploration proceeds westward, from the Cape Yakutat area, LNG processing facilities would be required. For Yakutat, facilities with a capacity of 322 MMCFGPD would be required by 1983, peaking at 700 MMCFGPD in 1985. Cape Junken would require a 350 MMCFGPD capacity by 1986, peaking at 700 MMCFGPD by 1988. Kodiak would require a 350 MMCFGPD capacity by 1989, peaking at 700 MMCFGPD by 1990.

Exhibit A-12 shows the assumed location of facilities. Exhibit A-13 shows the assumed development pattern.

BEAUFORT SEA

General Assumptions

This alternative involves development of the Alaskan offshore area extending from the U.S.-Canadian border to Point Barrow in the Beaufort Sea. In developing the initial exploration and production projections, we assumed that drilling in icebound waters will be limited to depths of 20 feet or less until about 1985.

Currently, federal and state lease sales are scheduled for 1975, 1976, 1977, and 1978. Given the existence of some promising geologic structures offshore from and within the National Arctic Wildlife Range, significant offshore discoveries in the Beaufort Sea would probably result in a lease sale off the coast of the Range. To project the near-maximum impact of oil and gas development, it was assumed that even this sensitive offshore acreage will be leased in 1980.

USGS estimates of economically recoverable oil reserves in the Beaufort Sea are 3.3 billion barrels. It was assumed that this oil will be discovered in four major fields.

Exploration Assumptions

Until 1985, exploration will be confined to offshore islands and/or to water depths of 20 feet. After 1985, new technology will make drilling in deeper waters possible.

With announced plans and projecting exploration paralleling the Prudhoe "model," exploration will begin in 1975 and is expected to continue until about 1990. This year Mobil may have a discovery independent of the main Prudhoe Bay discovery. If not, a discovery of 300 million barrels of oil and 1 trillion cubic feet of gas was assumed to occur between 1975-1977. Other discoveries were assumed in 1978, 1981, and 1984, consisting of an average of 1 billion barrels of recoverable oil reserves and 2 trillion cubic feet of gas per discovery. A discovery may actually consist of several smaller pools in the same general area and therefore economical to develop. Each discovery was assumed to contain both oil and gas in economic quantities. In addition, one gas discovery was assumed in 1986.

Development Assumptions

Completion of development wells was assumed to lag discoveries by 2 years. Oil development wells will use 320-acre spacing. Development will be complete by 1990. Gas development with 640-acre spacing will coincide with oil development, except for the gas discovery indicated in 1986. This discovery was assumed for the younger strata off the Arctic Wildlife Range with a potential comparable to a MacKenzie Delta gas field.

Production Assumptions

Oil production is expected to follow exploration by 6 years. Average production-rate per well in all but the Mobil "discovery" was assumed to be 4,000 BOPD initially, declining to 2,000 BOPD, and then remaining relatively constant because of the application of waterflooding to the reservoirs. The Mobil discovery was assumed to be 2,000 BOPD declining to 1,000 BOPD. The floor rate will be 112,000 BOPD in 1981, increasing to 818,000 by 1990, then declining.

Gas production was assumed both as a by-product of oil production and from the gas wells. Each oil well will produce gas at a rate of 1 MMCFGPD, and each gas well at a rate of 7 MMCFGPD, peaking in 1991 at 2 BCFGPD.

Transportation and Related Facilities Assumptions

The onshore facilities required to support this development will be a dock for summer use, an airstrip for delivery of supplies in the winter, and permanent quarters for 200 beds. Apart from the wells and rigs, additional producing facilities required will be an onshore gathering center and oil/gas separation facilities, and a small topping (distillation) plant with a capacity of 4,500-5,000 BOPD to provide fuel oil to power the equipment.

In order to transport oil and gas to the Lower 48, pipeline facilities, terminals, and liquefaction plants will be required. In the short-term, looping of the Alyeska pipeline would be required for the expected oil production in 1981-1983. By 1984, a new 30" pipeline would be required from the North Slope. While a number of trans-Canada and trans-Alaska routes could be used, we assumed that this new pipeline would parallel the Alyeska line and require an oil terminal of suitable capacity. We assumed that a 400,000 BOPD terminal would be built in the Valdez area by 1981, with capacity doubling to 800,000 BOPD by 1984. (These increments are over and above the increments added in the Other Prudhoe Private Development scenario.)

Again assuming use of the existing utility corridor, natural gas transportation would require additional compressor stations on the El Paso pipeline until 1984 when a new 36" line could come on stream. Liquefaction and terminal facilities would have to be expanded to handle an additional 1,500 million CFGPD by 1986.

Exhibit A-14 shows the possible facility location. Exhibit A-15 shows the assumed development pattern.

BERING SEA

General Assumptions

We assumed that leasing and exploration will commence in late 1976, when the Department of the Interior has scheduled a sale in the St. George Basin, in the area near the Pribilof Islands. Subsequent sales, beginning with Norton Sound, were assumed to occur at 2-year intervals, ending in 1986.*

The Bering Sea alternative is complicated by potential native and state leasing in the Bethel Basin, which extends to Kuskokwim Bay and includes the land area surrounding Norton Sound. It was assumed that some exploratory activity will start in these areas prior to federal lease sales in the Bering Sea, and will tend to escalate the potential of the outer continental shelf areas.

At present, only geophysical surveys have been conducted in the Bering Sea. As a result, the potential of the area is undetermined.

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* The Bristol Basin, which consists of Bristol Bay and adjacent onshore areas, is described later. See the description of the Bristol Bay development alternative.

Using USGS estimates, we have assigned a potential of 2.2 billion barrels of oil and 5.7 trillion cubic feet of gas to the area.

Exploration Assumptions

Assuming exploration and development will be similar to the Gulf of Alaska alternative, we estimated that there will be 50 geologic structures requiring 200 exploratory wells.

Exploration was assumed to begin in 1976, and be completed by 1997, resulting in discoveries in 1979, 1980, 1981, 1982, 1983, 1985, 1986, 1993, and 1994. Four oil discoveries of 500 million barrels of oil each and one of 200 million barrels of oil were assumed. (Each discovery may in fact consist of several smaller discoveries in the same area.) Smaller discoveries may continue into the 1990's to extend the life of development and production facilities, but this was too tentative an assumption to incorporate in the development scenario. For this offshore area, approximately 5 delineation wells will be drilled per discovery.

Development Assumptions

Development will begin in 1982, and be completed in 1998. As in the case of other regions, 320-acre spacing for development wells, with 16 wells to a platform, was assumed.

Production Assumptions

When the Bering Sea begins oil production in 1984, the total output is estimated to be 128,000 BOPD, increasing to 468,000 BOPD in 1991. Average production per well is estimated at 2,000 BOPD initially, declining to 1,000 BOPD, at which point waterflooding will probably be used to sustain an economic rate until the fields are depleted.

Transportation and Related Facilities Assumptions

The large distances between potential fields make separate development and production facilities necessary for each field. The land facilities required to support production consist of a dock for water access in the summer, an airstrip for continuous access, and permanent quarters.

Production itself will be almost entirely sea-based. Offshore tanker loading has been assumed for both the Pribilof Island and the Norton Sound areas.

Exhibit A-16 shows the facilities assumptions. Exhibit A-17 shows the development assumption.

LOWER COOK INLET

General Assumptions

This alternative involves development in the southern portion of the Cook Inlet Basin. Six oil fields and 21 gas fields have been discovered in the northern portion of the basin. Four lease sales were assumed under the Department of the Interior schedule for 1975-1978, with one sale occurring each year. As many as 2.5 million acres could potentially be leased by a joint federal/state program through the mid-1990's. The USGS estimated the potential recoverable reserves in the Lower Cook Inlet at 1.2 billion barrels of oil and 2.7 trillion cubic feet of gas (1975 estimate).

Exploration Assumptions

The closeness of the area to known oil and gas production is likely to induce a high level of exploration. Exploration is expected to begin in 1977 and be completed by 1989, assuming lease sales are conducted according to DOI and State of Alaska schedules. It has been assumed that 3 oil and 2 gas discoveries will occur during this period, mostly within 8 years of the commencement of exploration. Five delineation wells to outline the field were assumed in the two years subsequent to each discovery.

Development Assumptions

It was assumed that the discovery size will be 400 million barrels of oil and 800 billion cubic feet of gas. These are the average sizes of the Northern Cook Inlet discoveries. Discoveries may consist of several adjacent, smaller fields allowing simultaneous development and use of the same transportation facilities. Five platforms, with 16 development wells each, were assumed to be necessary for each oil field development. Eight wells per year were assumed on each platform until development of the platform has been completed. Gas development was assumed to require 320-acre spacing, with 16 wells being drilled from each platform.

Production Assumptions

The initial well flow rate in the Lower Cook Inlet was assumed to be 96,000 BOPD, increasing to 296,000 BOPD by 1988, when the field would be put on secondary recovery. Gas was assumed to be produced both as a by-product of oil production and from gas wells. Each oil well was assumed to produce 500,000 CFGPD and each gas well 10 MMCFGPD.

Transportation and Related Facilities Assumptions

As production of oil and gas increases in Lower Cook Inlet, more oil and gas facilities will be constructed on the Kenai Peninsula to support producing activities. Offshore platforms will have the facilities for gas/liquid separation and self-sustaining power generation. Required new facilities onshore, will include a dock and loading facility for oil and gas transport. Housing for personnel will be in adjacent towns.

Oil produced offshore will flow to onshore gathering centers and from there to storage at a new terminal. If oil development occurs as expected, a new 300,000 BOPD crude terminal could be built on the Kenai Peninsula adjacent to the producing areas, perhaps near Anchor Point at the end of Kachemak Bay.

Gas produced in the Lower Cook Inlet was assumed to be processed and liquefied onshore in one or more new LNG plants. This facility in the Lower Cook Inlet area is expected to be built on the land near Anchor Point. Existing LNG facilities are currently operating in the Upper Cook Inlet. However, as oil and gas development occur in the southern section, new LNG facilities for the greater volume of gas will be required there. To process and transport all of the gas anticipated from this province, gas processing, liquefaction, and terminal facilities will have to have a total capacity of 720 million SCFGPD by 1990, with gas shipments beginning in 1985. The associated terminal would have two berths capable of serving LNG tankers.

Exhibit A-18 shows the assumed facility location. Exhibit A-19 shows the development assumption.

KOTZEBUE - KOTZEBUE SOUND AREA

General Assumptions

This arm of the Chukchi Sea was considered a separate oil and gas subregion because it consists primarily of native and state-controlled acreage and because exploratory drilling is already under way on native lands. This distinguishes Kotzebue development from the much later development expected in the Chukchi Sea.

The State of Alaska's Department of Natural Resources estimates potential recoverable reserves at 700 million barrels of oil and 5 trillion cubic feet of gas. Based on USGS estimates, however, the potential was lowered to 400 million barrels of oil and 1.2 trillion cubic feet gas.

Exploration and Development Assumptions

Assuming the state will obtain leasing rights to most of Kotzebue Sound, exploration will probably proceed rapidly. Native lands will be explored under concession agreements already negotiated.

Onshore and offshore leasing is expected to occur during 1975-1983, and will result in two discoveries in 1978 and 1980 of about 200 million barrels each. Gas discoveries were assumed to occur in 1979 and 1982, with reserves of 600 billion cubic feet each. Two delineation wells were assumed per discovery well. Development will probably cover the period from 1980 to the end of 1986.

Production Assumptions

Initial oil production is likely to occur in 1982, reaching a peak of 117,000 BOPD in 1984. Wells will produce 1,500 BOPD, declining to 750 BOPD, at which point waterflood will be initiated. Gas wells were assumed to produce 5 MCFGPD.

Transportation and Related Facilities Assumptions

Support facilities are likely to include expansion of the airstrip at Kotzebue, construction of a dock, a small (2,000-2,500 BOPD) topping plant for fuel oil, and permanent living quarters. An onshore gathering center with a 120,000 BOPD capacity will also be required.

Because of pack ice, year-round tanker operation in Kotzebue Sound is unlikely. Even if tankers like the ESSO Manhattan were fitted or designed with special hulls, the ice movements would undoubtedly damage any kind of fixed berth or single-point mooring device now known. Consequently, it was assumed that a small (120,000 BOPD) crude oil pipeline with adequate terminal facilities will be required by 1984 to deliver oil from Kotzebue to Norton Sound.

Exhibit A-20 shows the assumed facility locations. Exhibit A-21 shows the assumed development pattern.

BRISTOL BAY

General Assumptions

The Bristol Basin is a potential oil-producing area covering about 95,000 square miles of Bristol Bay (a section of the Bering Sea) and adjacent onshore areas. Development of this region will be complicated by the fact that federal, state, and native leasing programs must be taken into consideration. However, since the higher potential areas lie in the 80 percent of the basin offshore, most of the exploration, development, and production was assumed to occur in the federal and state offshore acreage.

Leasing in the Bristol Basin area is expected to follow three separate schedules, depending on whether the acreage is federal-, state- or native-owned. Federal sales are expected to begin in 1976 and recur at 2-year intervals until 1984. Only one state sale is expected (in 1980). Native concession agreements with oil companies are likely to be made by 1980.

Exploration Assumptions

Nine exploratory wells have already been drilled onshore. Another 10 onshore wells are expected in the next 5 years, primarily to satisfy native concession agreements. Offshore exploration will not begin until 1977, and will probably not be completed until 1991.

The potential recoverable reserves were assumed to be 700 million barrels of oil and 1.6 trillion cubic feet of gas, 90 percent of which is offshore. In the basin, approximately 25 potential structures were assumed, requiring 100 exploratory wells. Oil discoveries are anticipated in 1979 and 1982, gas discoveries in 1980 and 1984. The discoveries were assumed to be 350 million barrels each. Each discovery may actually consist of several smaller fields found during delineation. In each case, 5 delineation wells are expected per discovery.

Development Assumptions

Development (mainly offshore) of the Bristol Bay area is expected to begin in 1982 and to be completed by 1989. As in other areas, 16 wells per platform with 320-acre spacing were assumed.

Production Assumptions

Initial (1984) *total* production is expected to be 120,000 BOPD, peaking in 1988 at 212,000 BOPD. The initial flow rate per well will be 2,000 BOPD. As the well-production rate declines to 1,000 BOPD, waterflooding will be instituted to sustain that rate until the field is depleted. Gas production is assumed to be 10 MMCFGPD for gas wells, 500,000 CFGPD for oil wells.

Transportation and Related Facilities Assumptions

Since most of the production will be offshore and tankers will take on the oil offshore, it was assumed that permanent onshore facilities requirements will be small: a dock for summer use, an airstrip for access throughout the year, and living and service facilities.

For natural gas, we assumed that a small (400 MMCFGPD) processing, liquefaction, and terminal complex will be required by 1984.

Exhibit A-22 shows the assumed facilities locations. Exhibit A-23 shows the assumed development pattern.

NAVAL PETROLEUM RESERVE - 4

General Assumptions

Naval Petroluem Reserve-4 (NPR-4) encompasses an extensive area of northern Alaska, from the Colville River in the east to approximately Icy Cape in the west. It extends from the coast of the Arctic Ocean to at least 50 miles south of Lookout Ridge in the Brooks Mountain Range.

Potential reserves are estimated at 6.5 billion barrels of oil and 12 trillion cubic feet of gas. The normal leasing procedure is not expected within NPR-4 unless Congress places the area under the aegis of the U.S. Department of the Interior. It was assumed, however, that the U.S. Navy will continue to manage, and therefore control, exploration and development of oil and gas in the region. In any case, all development was assumed to be conducted under contract to either the Navy or the Department of the Interior.

Exploration Assumptions

It was assumed that exploration will be pursued on the basis of maximizing reserves rather than following a competitive strategy. The first 10 years of exploration are expected to be concentrated in the northern half of NPR-4, with further exploration focusing on the southern portion from 1985 to 2000.

We assumed the first stage of exploration will commence after 1975, with discoveries in 1978, 1980, and 1983. Each discovery was assumed to be a medium-sized field with reservoir rock resembling that found in the Prudhoe Bay area (Sadlerochit, Lisburne, Kuparuk). Reserves were assumed at 2 billion barrels of oil and 3 trillion cubic feet of gas for each discovery. (It should be noted that discovery of a field would not necessarily encourage accelerated exploration in this alternative.)

The second stage of exploration, projected to occur from 1988 to 1997, was assumed to lead to discoveries of several small fields the size of Umiat (100 million barrels of oil) or of Gubik (500-1000 billion cubic feet of gas). These would be developed in the late 1990's on a basis similar to the Other Prudhoe Private Development scenario.

Development Assumptions

Development of the fields discovered in 1978 in the northern portion of NPR-4 would commence in 1981 and be completed by 1991. Development of the three later fields would begin in 1993 and end in 1999.

Production Assumptions

A 14-year life for oil fields and a 10-year life for gas fields was assumed. Initial production from the northern fields is expected to be 456,000 BOPD in 1984. Total production will rise to a peak of 1.4 million BOPD in 1990 as other fields are brought into production. Gas production was estimated to commence at 780 MMCFGPD in 1985, reaching a high of 2.7 billion CFGPD by 1995. The production rate for the northern oil field wells was assumed to be 3,000 BOPD initially, declining to 2,000 BOPD. The rate for the smaller fields was assumed to be 1,000 BOPD initially, declining to 500 BOPD. Each oil well is expected to produce 4 MMCFGPD; each gas well 10 MMCFGPD in the northern fields and 5 MMCFGPD in the southern portion. We assumed 320-acre spacing for oil development, 640-acre spacing for gas development.

Transportation and Related Facilities Assumptions

The NPR-4 alternative assumed an original plan to loop into the TAPS pipeline and either the Arctic or the El Paso gas pipeline, if constructed. However, as field discoveries demand additional capacity in 1986, new pipelines will have to be constructed along the TAPS and the gas line routes. Work on these additional pipelines is expected to begin in 1983 and be completed by 1989.

An alternative route south from NPR-4 linking with east-west pipelines to the TAPS route in the east or a new western Alaskan pipeline to the west is also feasible. A more likely occurrence is a pipeline to the origin of the TAPS line because, in the course of constructing the TAPS pipeline, all major support structures (such as bridges) have been designed to accommodate a second crude pipeline should it become necessary. A considerable construction cost saving would be achieved by using the TAPS route and a major parallel pipeline.

Small diameter pipelines will connect the fields to a central gathering center with facilities of Prudhoe Bay size. Two 150-mile long 40" lines were assumed to connect the gathering center to TAPS and the gas pipeline. Each field is expected to have large, temporary facilities during development, with small-to-medium permanent facilities during production. Dock facilities will also be required.

Exhibit A-24 shows the assumed facilities locations. Exhibit A-25 shows the assumed development pattern.

CHUKCHI SEA

General Assumptions

We assumed that leasing and exploration in this region will not commence until 1980, or offshore development until 1985, when technology development will make year-round exploration and development in ice-bound waters deeper than 20 feet possible. We also assumed that federally-sponsored development of NPR-4 and private development in the Point Lay area west of NPR-4 will provide geologic information about this unexplored area.

Leasing in the Chukchi Sea is not expected before 1980, when both state and federal offshore areas were assumed to be available. The USGS has estimated a potential of 6.4 billion barrels of oil and 19.8 trillion cubic feet of gas for this region. We believe that this valuation may be excessive. However, as the ranking of the scenario is low, with most of the development taking place in the 1990's, we have used the USGS estimates. They provide an "up-side" estimate of potential development for the northern portion of Alaska.

Exploration Assumptions

In the absence of detailed seismic analysis, we have assumed that 45 geologic structures requiring 180 exploratory wells will be explored. Exploration will begin in 1980 and be completed by 1999. A small, 300 million barrel discovery was assumed for 1982 for the Point Lay-Cape Lisburne area, including some onshore acreage. One billion barrel discoveries were assumed for 1985, 1987, 1990, and 1994. A 2 billion barrel discovery was assumed for 1989. (Each discovery may consist of several smaller discoveries in the same area.) Six gas discoveries, each of 3 trillion cubic feet, were postulated between 1983 and 1995. An average of 5 delineation wells per discovery was assumed.

Development Assumptions

The first development will occur onshore in the Point Lay-Lisburne area in 1984 and will continue through 2000. As in other areas, 320-acre spacing was assumed. We assumed 16 wells per platform for all development except the 1982 discovery (20 wells per platform).

Production Assumptions

Initial total production from Chukchi is anticipated to be 112,000 BOPD, with peak production of 1.562 million BOPD in 1995. Initial well production was assumed to be 4,000 BOPD in all but the 1982 discovery (2,000 BOPD). This will decline to 2,000 BOPD, when waterflood will be employed. Gas wells were assumed to produce at 8 MMCFGPD. Field life was assumed to be 14 years for oil fields, 12 years for gas fields.

Transportation and Related Facilities Assumptions

Additional facilities required for Chukchi development consist of alternative pipeline connections to transport systems. The most likely alternative, given the assumed timing of Chukchi growth, is a pipeline linking Chukchi gathering centers to the NPR-4 pipeline system, connected to TAPS or a parallel pipeline to southern Alaska.

Exhibit A-26 shows the assumed facilities locations. Exhibit A-27 shows the assumed development pattern.

ARCTIC WILDLIFE RANGE

General Assumptions

The prospect of opening the Arctic Wildlife Range for oil exploration is bound to be strongly opposed by environmental conservationists. However, the likelihood of significant discoveries in adjacent offshore areas of the Beaufort Sea and the existence of large, high-potential geologic structures in the Range make eventual development of some kind quite possible. This scenario assumed that, by 1985, sufficient environmental precautions will have been taken and the need for oil will be so great that the Range will be opened for exploration.

Exploration and Development Assumptions

A cautious exploration program is expected to begin in 1985 and continue until 1990. One major discovery of Prudhoe-Lisburne Reservoir dimensions (2 billion barrels of oil and 6 trillion cubic feet of gas) assumed to occur around 1987 is plausible. Development of the field is likely to span the period 1991-1995.

Production Assumptions

Production is expected to parallel the Prudhoe Sadlerochit development, but to peak at 600,000 BOPD by 1995. Initial production rates per well are expected to be 3,000 BOPD, declining to 2,000 BOPD. This production level will be maintained by waterflooding. Gas production rate was assumed to be 10 MMCFGPD per gas well.

Transportation and Related Facilities Assumptions

A pipeline will be required across the North Slope to TAPS, where oil from the Range will fill the TAPS line as Prudhoe declines. Gas produced would be transported either by the proposed El Paso Trans-Alaska gas pipeline to Point Gravina or by the proposed Arctic Gas Pipeline through Canada. In either case, a gas pipeline would be required to connect the Arctic Wildlife Range field to a central flow station at the pipeline.

Exhibit A-28 shows the assumed locations of facilities. Exhibit A-29 shows the assumed development pattern.

C - FORMULATING DEVELOPMENT SCENARIOS

We selected appropriate assumptions to reflect the oil and gas development model for each of 12 different development alternatives:

1. Upper Cook Inlet and Prudhoe Bay oil (the base case)
2. Other private development at Prudhoe Bay
3. Prudhoe Bay natural gas
4. Gulf of Alaska
5. Beaufort Sea
6. Bering Sea
7. Lower Cook Inlet
8. Kotzebue Sound
9. Bristol Bay
10. NPR-4
11. Chukchi Sea
12. Arctic Wildlife Range

Exhibit A-3 is a map indicating the location of these areas.

Each of these 12 alternatives could have been evaluated individually, in isolation from the others. However, we believe that such evaluations would give a less realistic result than the approach we used, a cumulative progressive grouping of alternatives to form a series of interrelated scenarios. We selected this approach because:

1. Impacts tend to be cumulative, especially in Alaska. For example, Fairbanks, a major staging ground for the Alyeska pipeline, would most probably be affected if natural gas from the North Slope or a pipeline from Naval Petroleum Reserve-4 passed through the Alyeska corridor.

2. The purpose of the study was to postulate what could happen, given reasonable assumptions. A cumulative treatment is the most effective way of doing this.

The cumulative grouping of development alternatives into development scenarios was based on a subjective ranking of the alternatives by their likelihood of occurrence, from the most likely - the base case - to the least likely.* We arrived at this ranking after considering a variety of factors.

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* This ranking does not necessarily imply the sequence in which these areas will be developed.

Current plans for lease sales and announced exploratory drilling were assumed to indicate: (1) substantial interest on the part of the oil industry and/or the controlling agency; and (2) the degree of certainty that some level of development would occur in the next two decades. In the absence of any announced intentions to open an area for leasing or drilling, other factors such as proximity to an area under development, conflicts in ownership rights, and the availability of proven, environmentally safe technology were considered.

After ranking the 12 alternatives, we defined scenarios to be all of the activity that occurred in the previous scenario, plus the next most likely (in our opinion) development alternative. Thus, the first scenario is the most likely alternative, the base case; the second scenario consists of the base case plus other private development in Prudhoe Bay; the third scenario includes the base case, other Prudhoe development, and Prudhoe natural gas; and so on.

1. Upper Cook Inlet and Prudhoe Bay Oil (base case). These two areas form the base case because development of oil and gas wells is either already completed or in progress. That these areas will be important producing areas in the near future is a virtual certainty, given the approval of the appropriate environmental impact statements and the nation's urgent need for additional oil supplies.

2. Other Prudhoe Bay Oil. When the TAPS pipeline is completed, current projections indicate that only 1.6 BOPD of the pipeline's capacity will be used by presently planned Prudhoe Bay development. Unless development is accelerated at Prudhoe Bay, this available capacity would be used by some reasonably large discoveries that have been made adjacent to the existing and planned Prudhoe facilties. If Prudhoe Bay development were accelerated, these discoveries could be used to fill the pipeline as production at Prudhoe Bay declines. Although these fields have not yet been delineated, their proximity to the pipeline makes their commercialization highly probable.

3. Prudhoe Bay Natural Gas. Natural gas reserves on the North Slope have been delineated. Currently, two proposals for transporting the gas to the Lower 48 are before the Federal Power Commission. One proposal, filed by El Paso Alaska, a subsidiary of the El Paso Natural Gas Company, suggests the construction of an 809-mile pipeline, running south from Prudhoe Bay to the southern coast of Alaska at Gravina Point, paralleling the trans-Alaska oil pipeline. There the gas would be liquified and shipped by tanker to southern California where it would be regasified and pumped into existing distribution lines.

The second proposal submitted by the Arctic Gas Project (a consortium of 18 U.S. and Canadian gas companies organized into the Alaskan Arctic Gas Pipeline Company and Canadian Arctic Gas Pipeline Company) suggests the building of a 6,000-mile pipeline running southeast from Prudhoe Bay across Canada's MacKenzie River Delta to a point near Calgary, Alberta. There, the pipeline would branch, one leg going eastward to midwest and eastern U.S. markets, ending near Pittsburgh, Pennsylvania, and two other branches running westward to points near Los Angeles and San Francisco to serve the West Coast markets.

Without indicating a preference for either pipeline, we based this development alternative on the El Paso proposal because we believe the potential socioeconomic impacts of the El Paso proposal are far greater, and so more significant for this study, than those of the Arctic Gas proposal.

Although we arbitrarily selected the El Paso proposal as the basis for one of the 12 development scenarios, for the sake of completeness, we considered the alternative based on the Arctic Gas Project proposal (the cumulative impacts of the other Prudhoe Private Development plus Arctic Gas Project). This alternative was taken no further and we did not build on it in subsequent scenarios. Assuming approval of the El Paso proposal, the major uncertainty for this scenario appears to be the economic viability of building a pipeline and liquefaction plant to transport the gas to the West Coast.

Environmental concerns are not as great about gas transport as they are generally for oil. The probability for development of Prudhoe Bay natural gas is lower than the alternatives already cited, but very likely in the near future.

4. Gulf of Alaska. Offshore development seems likely because: (a) the probability of finding large fields is high; (b) the technology for producing oil from 500-600-foot depths is available; (c) the waters of the Gulf are ice-free; (d) the area is the closest by tanker to the West Coast, where most of the oil will be used; and (e) lease sale nominations have been made and a lease sale date set. The cost and difficulty of offshore drilling, especially in an area of seismic activity, is balanced by the advantage of not needing a major pipeline to transport the oil to a tanker terminal; single-point moorings are feasible.

5. Beaufort Sea. Without the prior discoveries and accumulated operating experience at Prudhoe Bay, the Beaufort Sea would probably not have been attractive. However, there is a moderately high probability of production because: (a) there are large, potential oil structures in areas adjacent to known production; (b) technology exists for exploratory drilling and delineation from natural and/or man-made islands in shallow waters (this is already being done in the MacKenzie River Delta in Canada); and (c) federal and state lease sales are scheduled in the next few years.

6. Bering Sea. Although seismic data indicate moderately promising structures in the Bering Sea, there has not been sufficient exploration to determine this region's potential. Lease sales have been scheduled for 1976, but no environmental impact statement has been submitted. The problems created by the winter ice formation and the competition for equipment with the Gulf of Alaska and other areas give the Bering Sea only a moderate chance of being developed by 1985.

7. Lower Cook Inlet. This region is adjacent to the Upper Cook Inlet, which is already producing both oil and gas. In addition, federal and state government lease sales have been scheduled for 1975. These two factors, coupled with the fact that Cook Inlet waters are relatively ice-free and convenient for tankers, indicate this region will be a likely development prospect. However, there has been a legal question over federal/state ownership, somewhat reducing the probability of development. The Supreme Court has ruled in favor of federal ownership, but the state may appeal the decision. Hearings will be held and an environmental impact statement prepared prior to any lease sale.

8. Kotzebue Sound. These native- and state-controlled lands and waters are already being explored under special exploration agreements. Although there is a promising potential, the location presents problems. Winter ice formation will interfere with offshore exploratory drilling and prevent, or at least interfere with, the use of tankers in the area. A pipeline may have to be constructed to connect the region with an ice-free port in the south, or with a port where ice will not interfere with shipping operations. In spite of the potential, therefore, we consider Kotzebue to have only a moderate probability of development by 1985.

9. Bristol Bay. Some onshore exploratory drilling has already taken place. Although the results have been negative so far, initial seismic analyses indicate a reasonably good potential for the area and lease sales have been scheduled. However, even if oil were discovered, transportation problems caused by midwinter ice and competition for drilling equipment would impede production. Moreover, no environmental impact statement has been filed. These factors taken together indicate only a moderate-to-low probability of development by 1985.

10. Naval Petroleum Reserve-4 (NPR-4).* Exploratory drilling commissioned by the U.S. Navy is already under way, and initial seismic analyses indicate the possibility of structures of Prudhoe magnitude. Since the major reserves are onshore, no new technology is required to tap the fields. A major uncertainty is the status of the state-claimed offshore acreage out to the 3-mile limit, and the outcome of the U.S. Department of the Interior's efforts to open the reserve to leasing, development, and production. Because of this there is a lower probability of development than for the previous alternatives.

11. Chukchi Sea. The Chukchi Sea, like the Bering Sea, is still a questionable development area. The area is remote from existing or planned pipeline and tanker transportation. Consequently, its development in this century will depend to a great extent on the discovery of large reserves in the adjacent onshore and Beaufort Sea areas. Moreover, ice movements in the deeper waters present drilling and production problems. The probability of development of the Chukchi Sea by 1985 is quite low.

12. Arctic Wildlife Range. This area has a large onshore oil potential that should make it attractive for exploration. However, the area has been withdrawn from exploration by the Department of the Interior, and there is strong environmental opposition to exploration of the area.

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* As this study was being completed, a number of Congressional bills on the fate of NPR-4 were pending. Among these are bills providing for transfer of NPR-4 to DOI, and for rapid exploration, and development, possibly aimed at financing of an oil storage program.

Several onshore provinces including the Koyukuk Basin, the Yukon-Kandik Basin, and the Copper River Basin were not considered when this ranking was established. Although they may be explored at some time in the future, the uncertain status of native and federal withdrawals precludes reasonable appraisal of their development and production. The USGS, in Circular 725, estimated the combined potential as 300 million barrels of oil* and 2 trillion cubic feet of gas.* This is a relatively small potential compared with the potential of other areas, and indicates smaller socioeconomic impacts on the Alaskan community

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* Mean estimate.

Exhibit A - 1

Exhibit A-1: Alaska Model Development

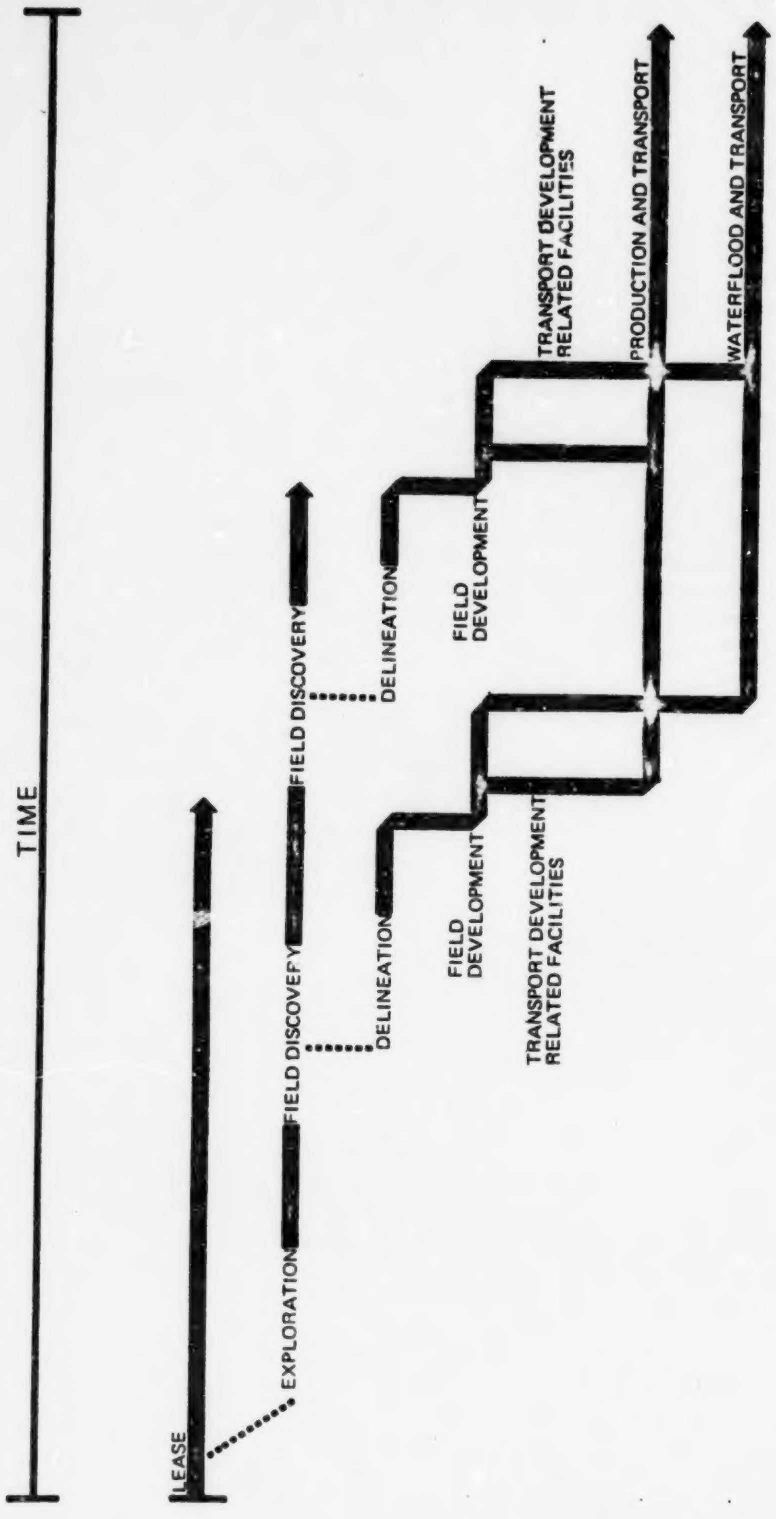

TIME
LEASE
EXPLORATION
FIELD DISCOVERY
DELINEATION
FIELD DEVELOPMENT
TRANSPORT DEVELOPMENT RELATED FACILITIES
FIELD DISCOVERY
DELINEATION
FIELD DEVELOPMENT
TRANSPORT DEVELOPMENT RELATED FACILITIES
PRODUCTION AND TRANSPORT
WATERFLOOD AND TRANSPORT

Exhibit A-2

Potential Onshore–Offshore Oil and Gas

Recoverable Reserves* – Alaska

Area	Oil (Billion Barrels) 5%	Oil Mean	Oil 95%	Gas (TCFG) 5%	Gas Mean	Gas 95%
Alaska–Total	49	27	12	132	76	29
Alaska Onshore	19	12	6	57	32	16
Alaska Offshore	18	15	5	80	44	8
North Alaska Onshore [1]	16	10	5	50	28	5
Central Alaska Onshore	1	.3	0	5	2	0
North Alaska Offshore	19	10	2	50	29	5
Western Alaska Offshore [1,2]	4	NA	1	10	NA	2
South Alaska Offshore	6	2.5	1	17	7	2

1. USGS used 25%–75% probabilities
2. USGS employed marginal probabilities

Area	Oil (Billion Barrels) USGS Mean	Oil RPA Estimate	Gas (TCFG) USGS–Mean	Gas RPA Estimate
Prudhoe Private		4.5		9.0
El Paso Gas		–		29
Gulf of Alaska	2.5		7.0	
Beaufort Sea	3.3		8.8	
Bering Sea	2.2		5.7	
Lower Cook Inlet	1.2		2.4	
Kotzebue Sound	.4		1.2	
Bristol Bay	.7		1.6	
NPR–4	NA	6.5	NA	10.0
Chukchi Sea	6.4		19.8	
Arctic Wildlife		2.0		6.0

* USGS employed probabilities for areas. Adding total reserves for areas, therefore, will not give listed total for Alaska.

Exhibit A - 3

Exhibit A-3
Development Alternative Areas.

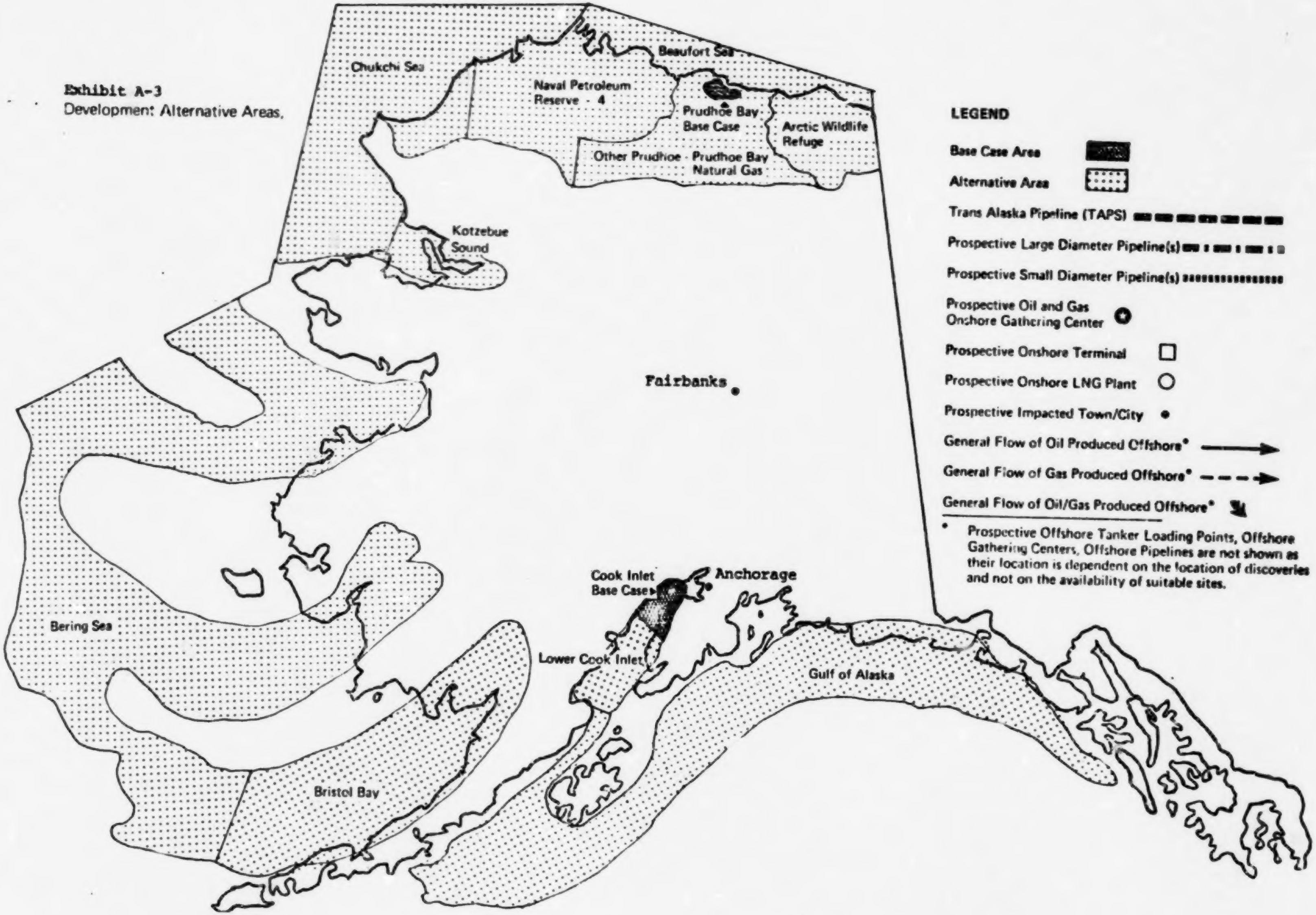

Chukchi Sea
Beaufort Sea
Naval Petroleum Reserve - 4
Prudhoe Bay Base Case
Arctic Wildlife Refuge
Other Prudhoe - Prudhoe Bay Natural Gas
Kotzebue Sound
Fairbanks
Cook Inlet Base Case
Anchorage
Lower Cook Inlet
Gulf of Alaska
Bering Sea
Bristol Bay
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A - 4

Exhibit A-4: Hypothetical Development Levels for Individual Development Alternatives
Alaskan Oil and Gas, 1977-2000

Development Alternatives	Recoverable Reserves		Initial Development Date	Production Schedule (thousand barrels per day; million cubic feet per day)											
	oil (billion barrels)	Gas (trillion cubic feet)		1977		1980		1985		1990		1995		2000	
				Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Cook Inlet Base Case	1.0	6	1958	195	300	195	400	175	800	90	800		800		300
Prudhoe Oil Base Case	9.6		1969	1200		1600		1600		1600		500			
Prudhoe Private															
Kuparuk	1.5-2.0	-	1978			384		250		250		100			
Lisburne	1.0-2.0	7.0	1980					500	1000	381	1000	179	1000	84	1000
Heavy Oil	0.2	-	1985							86		40			
Other	0.3	2.0	1985			—		—	—	100	400	47	400	—	400
Sub-Total	2.5-4.5	9.0				384		750	1000	817	1400	366	1400	84	1400
Prudhoe Gas-El Paso		29.0	1975-76				2100		3800		3900		4000		3300
Gulf of Alaska	2.5	7.0	1980					276	690	416	2072	385	880	170	416
Beaufort Sea	3.3	3.8	1979					564	1310	818	1774	374	1276	103	558
Bering Sea	2.2	5.7	1982					176	322	448	1134	350	1150	184	458
Lower Cook Inlet	1.2	2.4	1982					120	320	280	720	224	480	48	40
Kotzebue	.4	1.2	1980					113	160	74	320	39	160		
Bristol Bay	.7	1.6	1982					132	198	164	400	93	400	15	
NPR-4	6.5	10.0	1981					600	780	1400	2340	1148	1980	396	960
Chukchi Sea	6.4	19.8	1984							410	1136	1562	3072	1219	3136
Arctic Wildlife Refuge	2.0	6.6	1991									600	1000	400	1000

Exhibit A-5

Development Alternative 1: Base Case, Upper Cook Inlet and Prudhoe Bay Oil

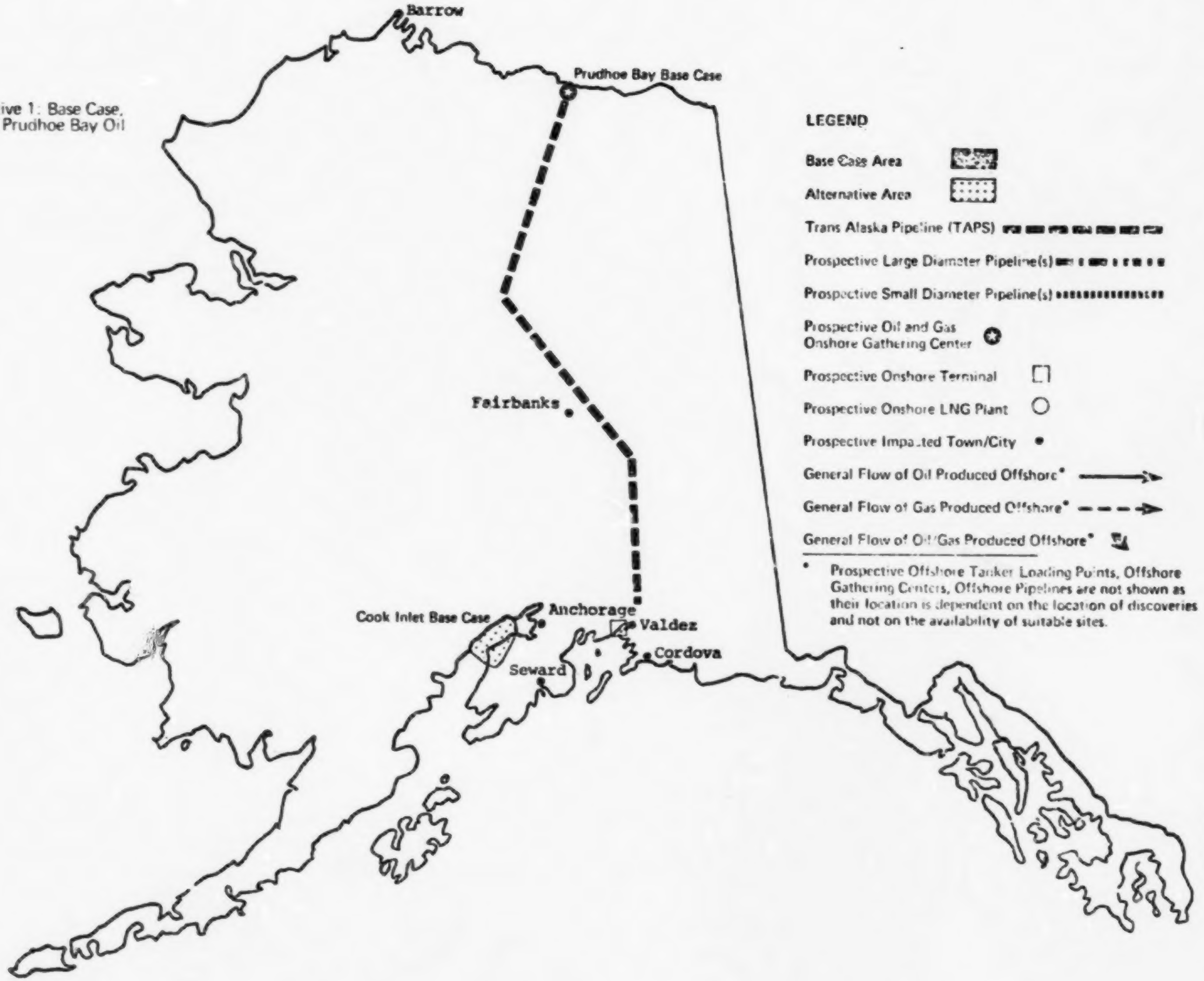

Barrow
Prudhoe Bay Base Case
Fairbanks
Anchorage
Valdez
Cordova
Seward
Cook Inlet Base Case
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-6

Development Alternative 1 – Cook Inlet Base Case

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)[1]																											
Discovery[1]																											
Delineation (No. of Wells)[1]																											
Development – Oil																											
Platforms																											
Wells – Total	8	8	8																								24
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms																											
Wells	8	8	16	8	8	8	8	16	8	8																	98
Production – Oil (MBOPD)																											
Total	195	195	195	195	195	195	195	190	190	180	175	170	160	160	120	90											1022 MMBO*
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)	400	400	400	400	400	400	500	600	700	800	800	800	800	800	800	800	800	800	800	800	800	800	700	500	400	300	6022 BCFG*

[1] No new exploration, discoveries or delineation.

* Total Cumulative Production

Development Alternative 1 — Prudhoe Oil Base Case

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells) [1]																											
Discovery [1]																											
Delineation (No. of Wells) [1]																											
Development – Oil																											
Platforms																											
Wells – Total [2]	16	24	32	64	48 (64)	32 (64)	6 (64)	(64)	(64)																		222 (456)
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms																											
Wells																											
Production – Oil (MBOPD)																											
Total [2]			1200 (1200)	1200 (1600)	1200 (1600)	1600 (1600)	1600 (2000)	1600 (2000)	1600 (2000)	1600 (2000)	1600 (2000)	1600 (2000)	1600 (2000)	1600 (2000)	1600 (1500)	1600 (1100)	1600 (850)	1200 (600)	900 (400)	675	500	375					9654 MMBO* (9654) MMBO*
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)																											

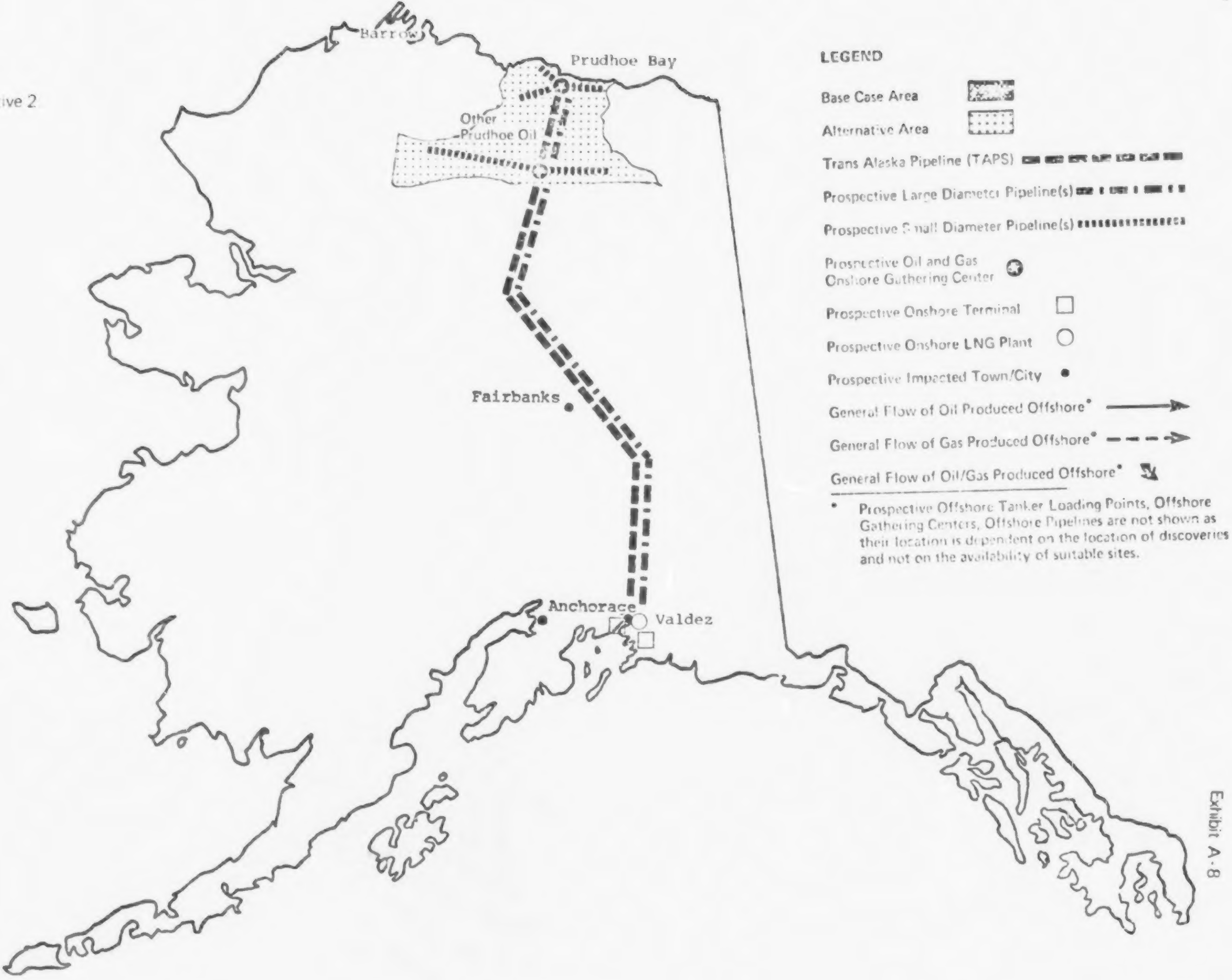
[1] No new exploration, discoveries or delineation.

[2] Number in parenthesis assumes accelerated production.

* Total Cumulative Production

Exhibit A-7

Exhibit A-8
Development Alternative 2
Other Prudhoe Oil


Barrow
Prudhoe Bay
Other Prudhoe Oil
Fairbanks
Anchorage
Valdez
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*

* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-8

Exhibit A-9

Development Alternative 2–Other Prudhoe Oil

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)	5	3	3	3	2	5	6	5	2	1																	35
Discovery [1]					X(X)	(X)	X																				
Delineation (No. of Wells)	6	9	6	1	2	2	2	2	7	6																	43
Development – Oil																											
Platforms																											
Wells – Total				28	32	56	88	118	78	50	42	84	92	42	10	10	10	10									750
First Discovery				28	32	36	58	68	28																		250
Second Discovery						20	30	50	50	50																	200
Third Discovery											32	64	72	32													200
Fourth Discovery											10	20	20	10	10	10	10	10									100
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms																											
Wells								25	25	25	35	10	10	10													140
Production – Oil (MBOPD)																											
Total				(112)	(240)	384	400	400	375	700	750	850	910	926	863	817	736	620	562	481	386	304	252	186	128	84	4053MMBO*
Kuparuk				(112)	(240)	384	400	400	375	250	250	250	250	250	250	250	250	200	200	150	100	75	56	42	30		1610MMBO*
Lisburne						(80)	(150)	(300)	(450)	450	500	600	600	516	443	381	328	282	243	209	179	154	132	114	98	84	1939MMBO*
Heavy Oil											(16	(48)	(84)	80	100	86	74	64	55	47	40	35	30				223MMBO*
Other North Slope											(20)	(60)	60	80	100	100	86	74	64	55	47	40	34	30			281MMBO*
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)								(250)	(500)	750	1000	1000	1300	1400	1400	1400	1400	1400	1400	1400	1400	1200	1000	800	500	200	6917BCFG*

1. (X) = gas discovery

*Total Cumulative Production

Exhibit A-10-1

Development Alternative 3:
Prudhoe Bay Gas – El Paso

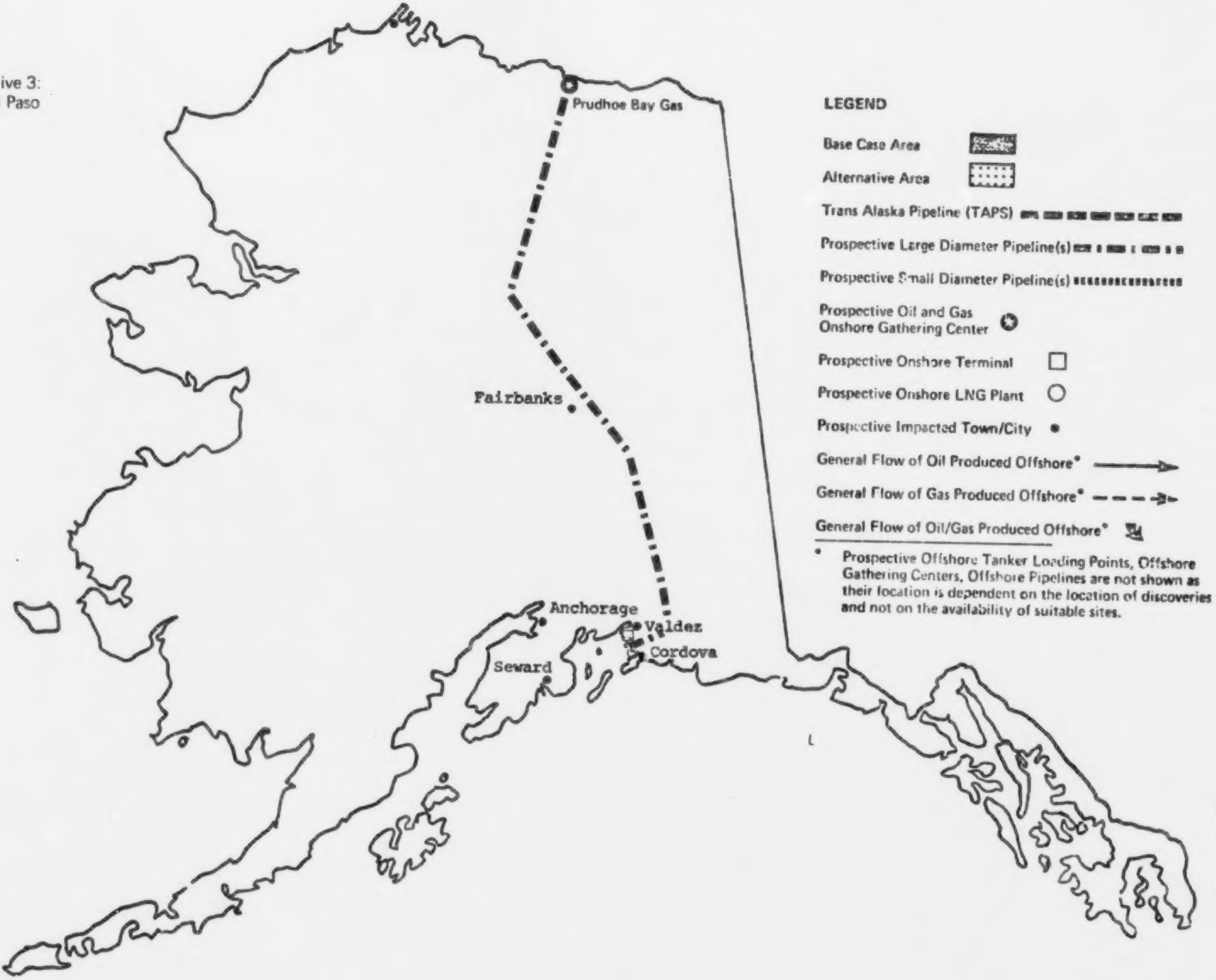

Prudhoe Bay Gas
Fairbanks
Anchorage
Valdez
Cordova
Seward
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-10-2

Development Alternative 3
Prudhoe Bay Gas — Arctic

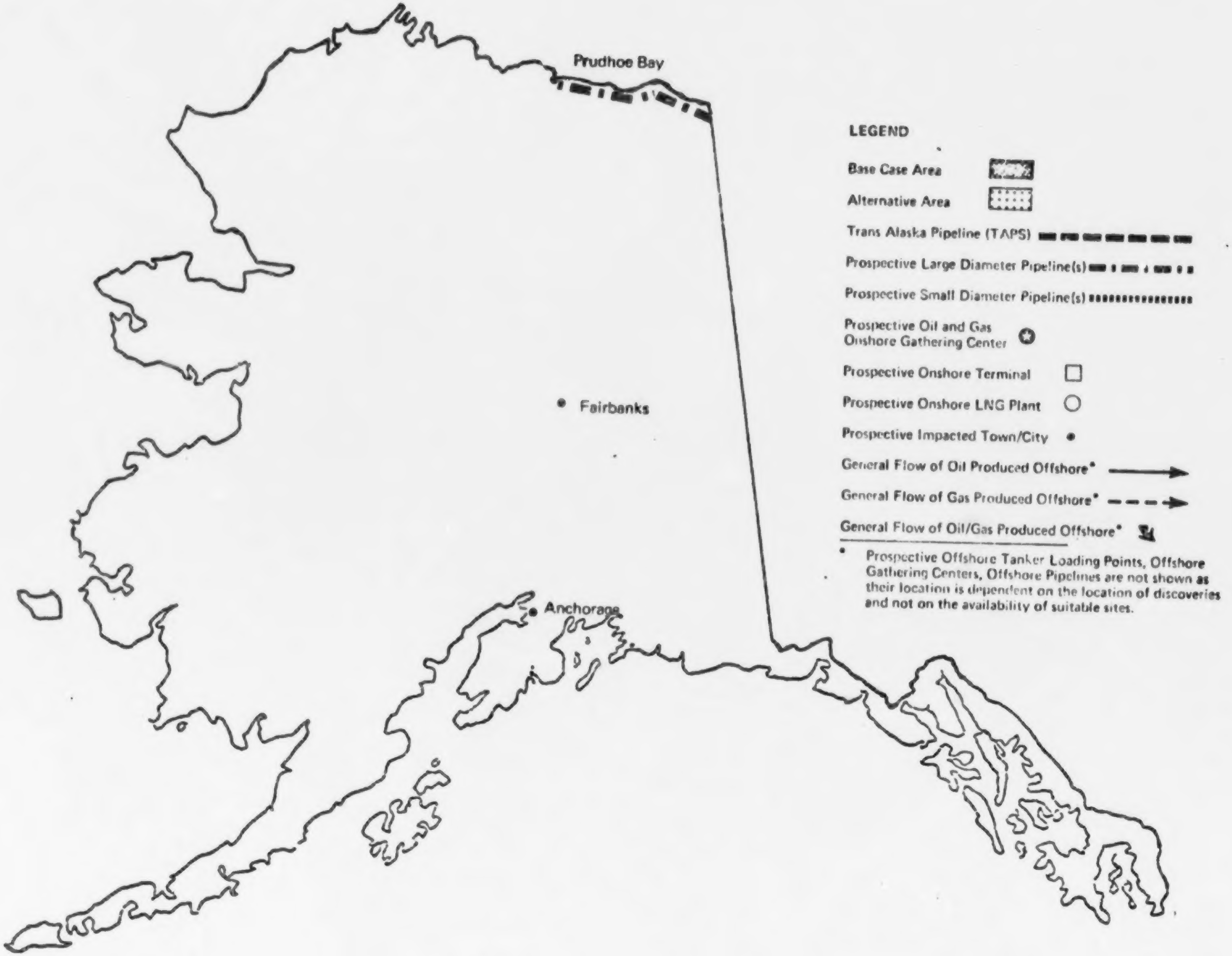

Prudhoe Bay
Fairbanks
Anchorage
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-11-1

Development Alternative 3—Prudhoe Bay Natural Gas – El Paso

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)	NO NEW EXPLORATION DISCOVERIES OR DELINEATION																										
Discovery																											
Delineation (No. of Wells)																											
Development – Oil																											
Platforms																											
Wells – Total																											
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms																											
Wells						8	16	32	32	24	8																120
Production – Oil (MBOPD)																											
Total																											
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)[1]			(800)	(800)	(1800)	1600	1800	2000	2600	3100	3100	3300	3200	3200	3300	3100	3200	3200	3200	3200	3200	3200	3200	3200	3200	(2700)	22557 BCFG*

[1] 800 MMCFGPD is Reinjected, the Remainder is Available to Pipeline.

*Total Cumulative Production

Exhibit A-11-2

Development Alternative – Prudhoe Bay Natural Gas – Arctic

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)	NO NEW EXPLORATION DISCOVERIES OR DELINEATION																										
Discovery																											
Delineation (No. of Wells)																											
Development – Oil																											
Platforms																											
Wells – Total																											
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms																											
Wells																											
Production – Oil (MBOPD)																											
Total																											
First Discovery																											
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)			(800)	(800)	(1800)	2000	2000	2000	2250	2250	2250	2250	2250	2250	2250	2250	2250	2250	2250	2250	2250						23300 BCFG*

*Total Cumulative Production.

Exhibit A-12

Exhibit A-12
Development Alternative 4:
Gulf of Alaska

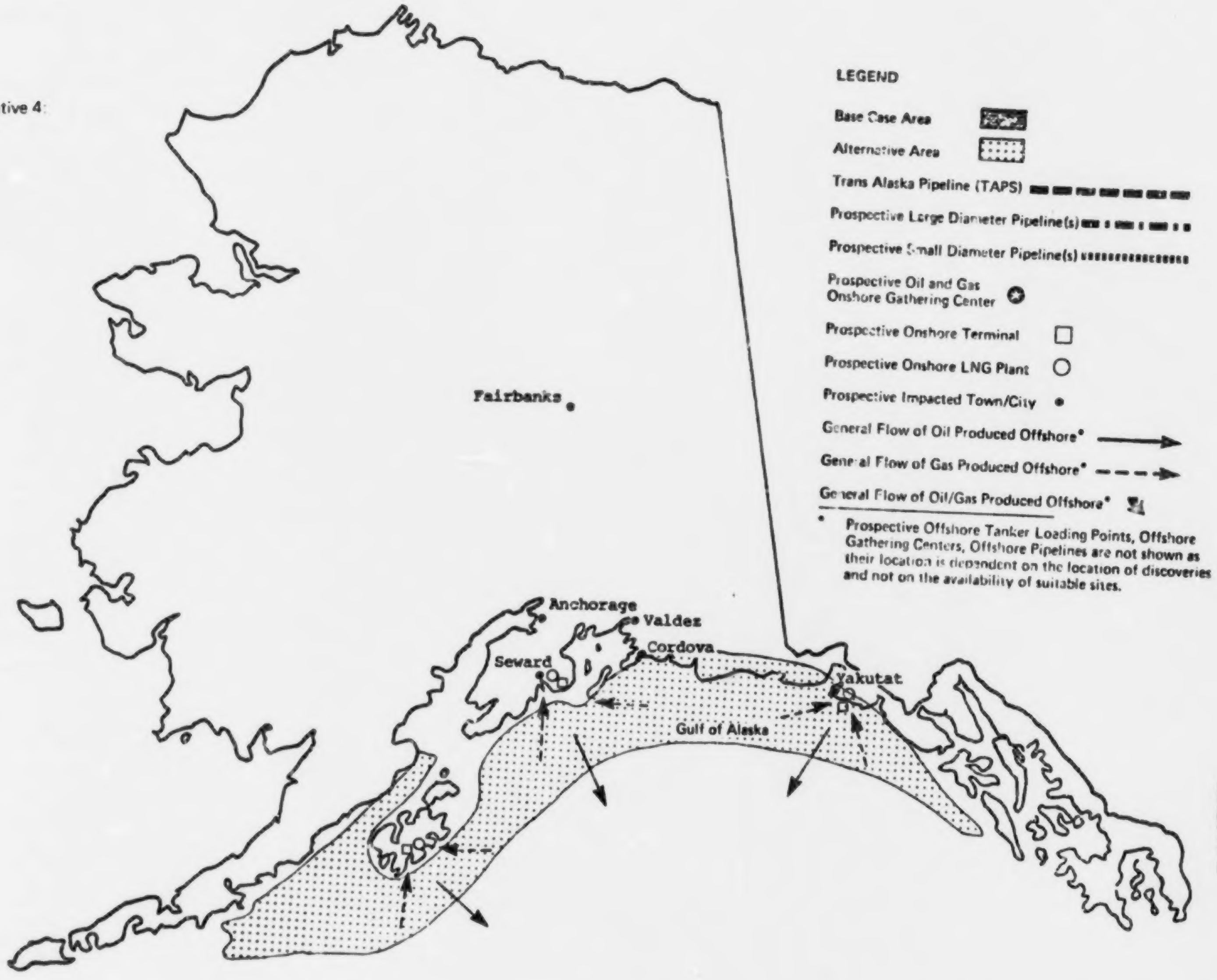

LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.
Fairbanks
Anchorage
Valdez
Cordova
Seward
Yakutat
Gulf of Alaska

Exhibit A-13

Development Alternative 4—Gulf of Alaska

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)	1	16	28	28	36	36	36	36	28	20	16	16	16	16	8	8	4										349
Discovery			x	(x)	x	(x)	x(x)	(x)	x	(x)	(x)	x															
Delineation (No. of Wells)				2	5	5	5	7	8	5	5	5	5	3													55
Development – Oil																											
Platforms						1	2	3	3	3	3	4	2	3	1	2	3										30
Wells – Total						8	24	40	48	48	48	48	48	40	32	32	32	24	8								480
First Discovery						8	24	32	24	8																	96
Second Discovery								8	24	32	24	8															96
Third Discovery										8	24	32	24	8													96
Fourth Discovery												8	24	32	24	8											96
Fifth Discovery															8	24	32	24	8								96
Sixth Discovery																											
Development – Gas																											
Platforms							1	1	1	2	2	1	1	2	1												12
Wells							6	12	16	22	28	26	20	22	22	14	4										192
Production – Oil (MBOPD)																											
Total						(16)	(64)	128	176	256	276	352	382	448	468	416	516	544	478	419	385	346	310	150	214	170	2380MMBO*
First Discovery						(16)	(64)	128	176	128	100	96	96	96	96	96	96	80	62	47	35	27	21				503MMBO*
Second Discovery								(16)	(64)	128	176	128	100	96	96	96	96	96	96	80	62	47	35	27	21		503MMBO*
Third Discovery										(16)	(64)	128	176	128	100	96	96	96	96	96	96	[illegible]	[illegible]	[illegible]	35	27	496MMBO*
Fourth Discovery												(16)	(64)	128	176	128	100	96	96	96	96	96	96	[illegible]	62	47	474MMBO*
Fifth Discovery															(16)	(64)	128	176	128	100	96	96	96	96	96	96	404MMBO*
Sixth Discovery																											
Production – Gas (MMCFGPD)						(4)	(76)	(212)	322	398	690	1046	1380	1436	1748	2072	1824	1836	1520	1200	880	812	836	504	464	416	7080BCFG*

1. (X) = gas discovery

*Total Cumulative Production

Exhibit A-14
Development Alternative 5
Beaufort Sea

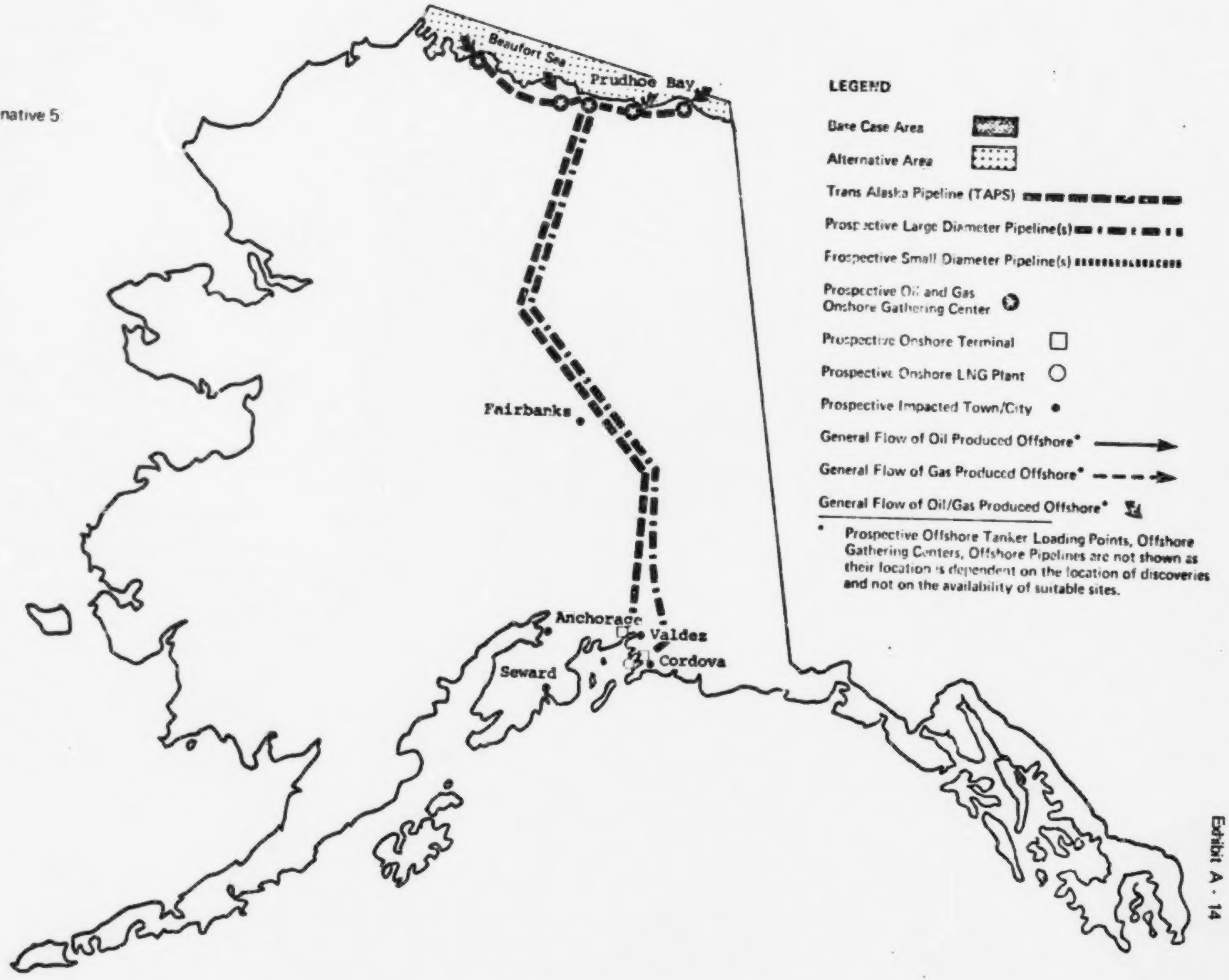

Beaufort Sea
Prudhoe Bay
Fairbanks
Anchorage
Valdez
Cordova
Seward
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A - 14

Exhibit A-15

Development Alternative 5—Beaufort Sea

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)	4	6	6	12	12	12	12	12	10	10	8	4	4	4	2	2											120
Discovery [2]	x[1]			x			x			x		(X)															
Delineation (No. of Wells)			1	1	2	3		2	3		2	3	2	3													22
Development – Oil																											
Platforms					2	3	2	3	1	2	3	1	2	3													22
Wells – Total					12	30	38	48	44	48	26	18	18	34	26	12											352
First Discovery					12	24	20	8																			64
Second Discovery						6	18	34	26	12																	96
Third Discovery								6	18	34	26	12															96
Fourth Discovery												6	18	34	26	12											96
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms					2	2	3	3	1	2	3	1	2	3	1	2	3										28
Wells					12	16	22	24	12	14	22	12	14	22	12	14	22	6									224
Production – Oil (MBOPD)																											
Total					(24)	(72)	112	360	408	448	564	616	640	756	801	818	661	565	502	445	374	329	266	182	137	103	3316MMBO*
First Discovery					(24)	(72)	112	128	72	64	64	64	64	64	57	53	38	29	22	17							308MMBO*
Second Discovery						(24)	(96)	232	336	384	268	216	192	192	192	192	163	128	96	73	54	41	30				1018MMBO*
Third Discovery									(24)	(96)	232	336	384	268	216	192	192	192	192	163	128	96	73	54	41	30	1018MMBO*
Fourth Discovery												(24)	(96)	232	336	384	268	216	192	192	192	192	163	128	96	73	972MMBO*
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)					(84)	(154)	252	904	714	828	1310	1396	1408	1624	1890	1774	2180	1820	1760	1600	1276	1060	868	702	584	558	8800BCFG*

1. Mobil's Gyndyr St. No. 2, drilled this year may represent this discovery. 2. All oil discoveries assumed to contain gas. One gas (X) discovery in 1986

*Total Cumulative Production

Exhibit A-16
Development Alternative 6
Bering Sea

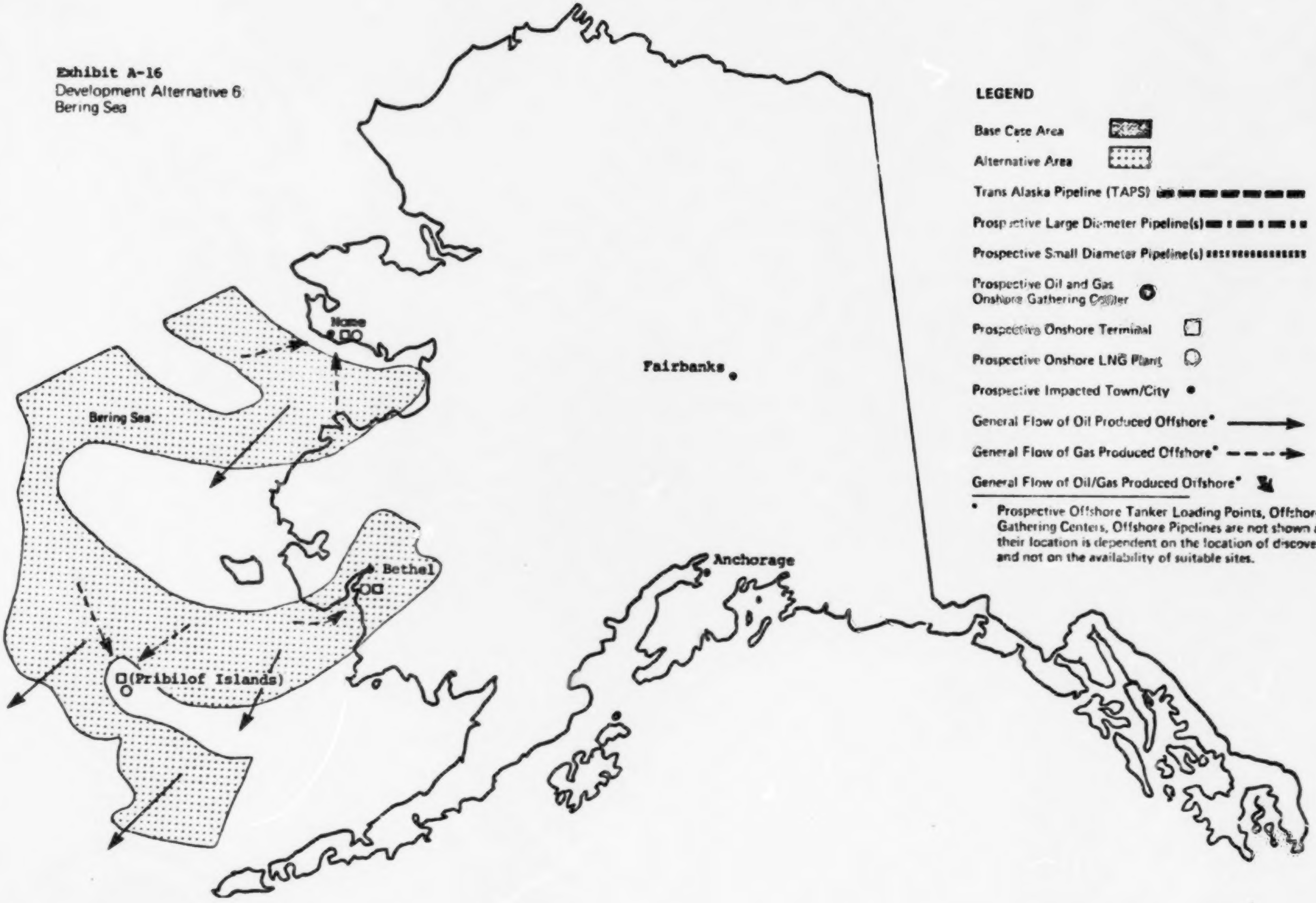

Fairbanks
Anchorage
Nome
Bethel
Bering Sea
(Pribilof Islands)
LEGEND
Base Case Area ▨
Alternative Area ░
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center ●
Prospective Onshore Terminal □
Prospective Onshore LNG Plant ○
Prospective Impacted Town/City •
General Flow of Oil Produced Offshore* →
General Flow of Gas Produced Offshore* - - →
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-17

Development Alternative 6—Bering Sea

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)		4	8	17	16	16	16	16	12	12	12	12	10	8	6	4	4	4	4	8	8	4	4				200
Discovery					X	(X)	X	(X)	(x)x		X	(X)							X	(X)							
Delineation (No. of Wells.						2	5	5	5	7	6	2	5	3						2	5	3					50
Development – Oil																											
Platforms								1	2	3	3	3	3	3	3	2	1					1	2				27
Wells – Total								8	24	40	48	48	48	48	48	40	24	8				8	24	16			432
First Discovery								8	24	32	24	8															96
Second Discovery										8	24	32	24	8													96
Third Discovery												8	24	32	24	8											96
Fourth Discovery														8	24	32	24	8									96
Fifth Discovery																						8	24	16			48
Sixth Discovery																											
Development – Gas																											
Platforms									1	1	1	2	1		1	1					1	1					10
Wells									6	12	16	22	22	14	10	12	10	4			6	12	10	4			160
Production – Oil (MBOPD)																											
Total								(16)	(64)	128	176	256	276	352	382	448	468	416	388	368	350	319	289	346	294	184	1[illegible]MMBO*
First Discovery								(16)	(64)	128	176	128	100	96	96	96	96	96	96	80	62	47	35	27	21		504MMBO*
Second Discovery										(16)	(64)	128	176	128	100	96	96	96	96	96	96	80	62	47	35	27	492MMBO*
Third Discovery												(16)	(64)	128	176	128	100	96	96	96	96	96	96	80	62	47	431MMBO*
Fourth Discovery														(16)	(64)	128	176	128	100	96	96	96	96	96	96	80	434MMBO*
Fifth Discovery																						(16)	(64)	96	96	48	88MMBO*
Sixth Discovery																											
Production – Gas (MMCFGPD)								(4)	(176)	(212)	322	398	690	1046	1098	1134	1426	1470	1470	1190	1150	870	830	786	750	458	5507BCFG*

1. (X) = gas discovery

*Total Cumulative Production

Exhibit A-18
Development Alternative 7:
Lower Cook Inlet

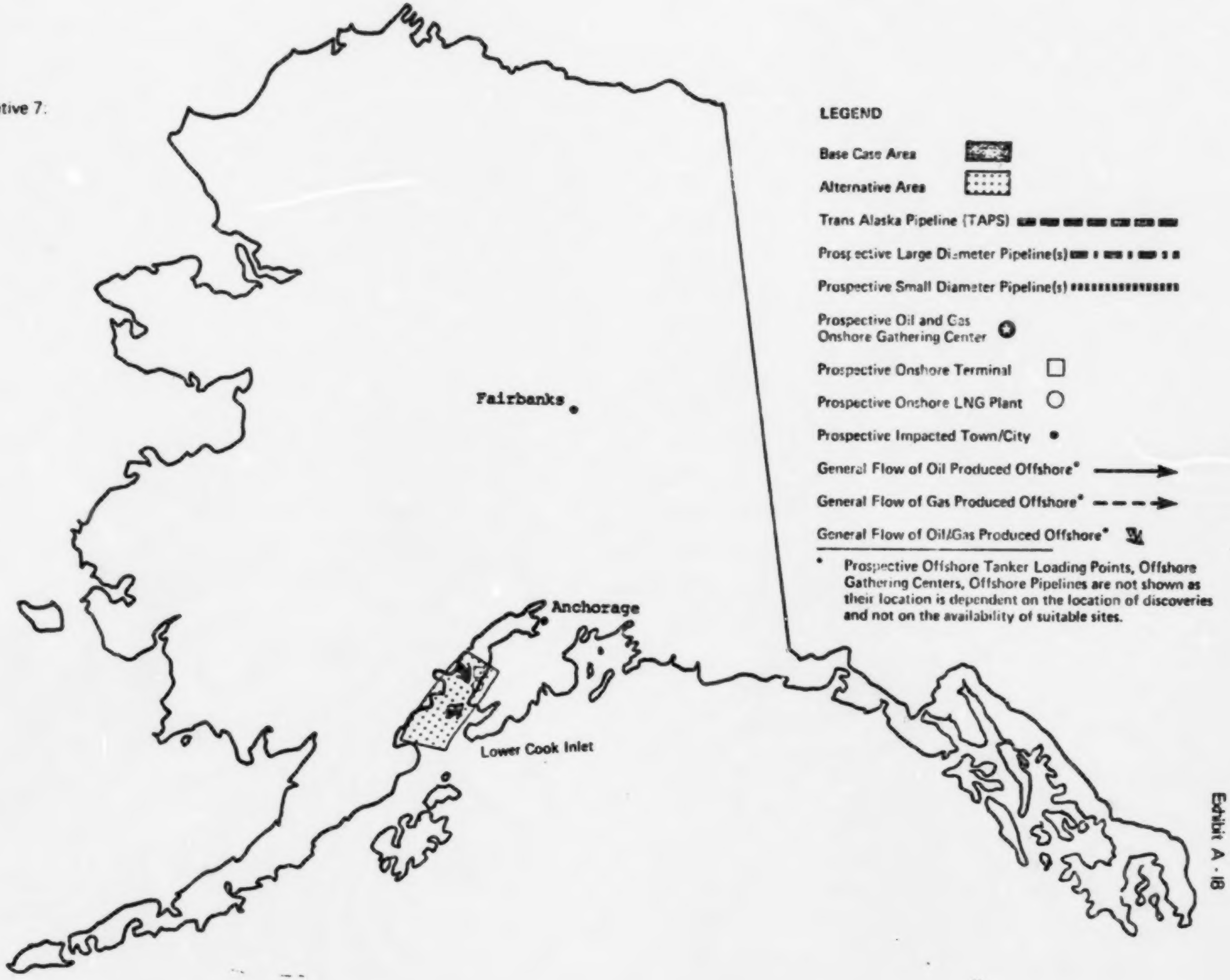

Fairbanks
Anchorage
Lower Cook Inlet
LEGEND
Base Case Area ▨
Alternative Area ▨
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal □
Prospective Onshore LNG Plant ○
Prospective Impacted Town/City ●
General Flow of Oil Produced Offshore* →
General Flow of Gas Produced Offshore* - - →
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-19

Development Alternative 7—Lower Cook Inlet

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)			8	16	16	16	16	16	16	16	8	8	8	4	4												152
Discovery					X	(X)	X		X	(X)																	
Delineation (No. of Wells)						2	5	5	3	2	5	3															25
Development – Oil																											
Platforms								1	2	3	2	3	2	2													15
Wells – Total								8	24	40	40	40	40	32	16												240
First Discovery								8	24	32	16																80
Second Discovery										8	24	32	16														80
Third Discovery												8	24	32	16												80
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms									1	1			1	1													4
Wells									6	12	10	4	6	12	10	4											64
Production – Oil (MBOPD)																											
Total										96	120	216	200	296	280	280	240	240	240	240	224	208	180	128	100	48	1218MMBO*
First Discovery								(12)	(48)	96	120	120	80	80	80	80	80	80	80	80	64	48	36				410MMBO*
Second Discovery										(12)	(48)	96	120	120	80	80	80	80	80	80	80	80	64	48			410MMBO*
Third Discovery												(12)	(48)	96	120	120	80	80	80	80	80	80	80	50	64	48	398MMBO*
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)								(4)	(76)	(216)	320	352	360	392	680	720	720	720	720	720	480	440	440	120	80	40	2468BCFG*

1. (X) = gas discovery

*Total Cumulative Production

Exhibit A-20

Development Alternative 8:
Kotzebue Sound

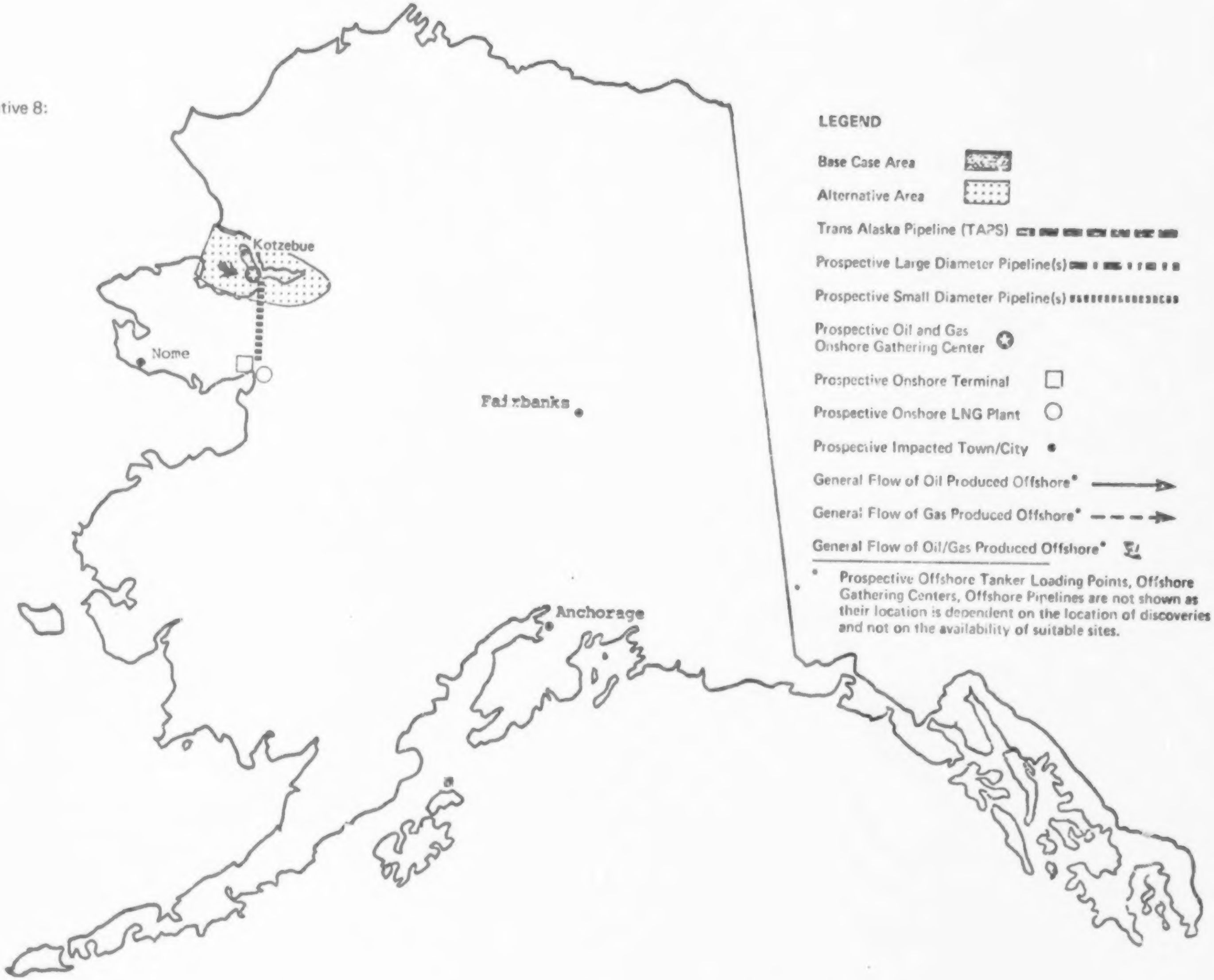

Kotzebue
Nome
Fairbanks
Anchorage
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal □
Prospective Onshore LNG Plant ○
Prospective Impacted Town/City ●
General Flow of Oil Produced Offshore* →
General Flow of Gas Produced Offshore* - - →
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A - 20

Exhibit A-21

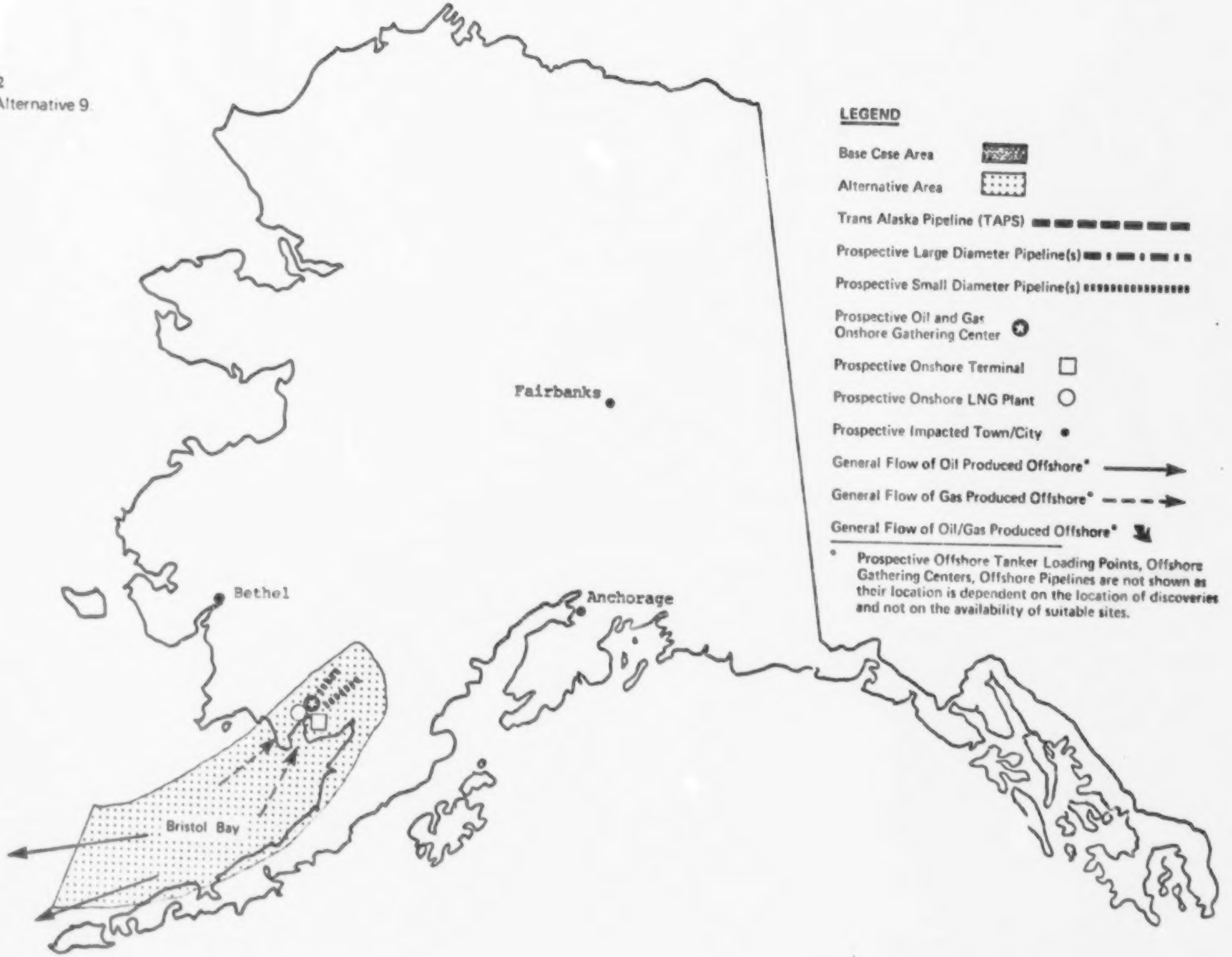
Development Alternative 8–Kotzebue Sound

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1939	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)	1	2	4	8	8	8	4	4	2																		41
Discovery [1]				X	(X)	X		(X)																			
Delineation (No. of Wells)					2	2	2		2																		8
Development – Oil																											
Platforms						1	1	1	1																		4
Wells – Total						6	12	18	24	18	12	6															96
First Discovery						6	12	12	12	6																	48
Second Discovery								6	12	12	12	6															48
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms								1	1			1	1														4
Wells								6	12	10	4	6	12	10	4												64
Production – Oil (MBOPD)																											
Total						(9)	(27)	45	63	117	113	113	87	78	74	74	74	68	62	50	39	19	14				398MMBO*
First Discovery						(9)	(27)	45	63	72	50	41	37	37	37	37	37	31	25	19	14						199MMBO*
Second Discovery								(9)	(27)	45	63	72	50	41	37	37	37	37	37	31	25	19	14				199MMBO*
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)								(30)	(90)	140	160	160	160	300	320	320	320	320	320	180	160	160	160	20			1168BCFG*

1. (X) = gas discovery

*Total Cumulative Production

Exhibit A-22
Development Alternative 9
Bristol Bay


Fairbanks
Bethel
Anchorage
Bristol Bay
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal □
Prospective Onshore LNG Plant ○
Prospective Impacted Town/City ●
General Flow of Oil Produced Offshore* →
General Flow of Gas Produced Offshore* - - →
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Development Alternative 9—Bristol Bay

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)			2	4	8	12	12	12	12	8	8	4	4	4	4	4	2										100
Discovery [1]					x	(X)		x		(X)																	
Delineation (No. of Wells)						2	5	3	2	3	2	3															20
Development – Oil																											
Platforms								1	2	2	1	2	2														10
Wells – Total								8	24	28	24	28	28	16	4												160
First Discovery								8	24	28	16	4															80
Second Discovery											8	24	28	16	4												80
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms								1					1														2
Wells								6	6	4			6	6	4												32
Production – Oil (MBOPD)																											
Total								(16)	(64)	120	132	100	204	212	180	164	160	145	130	117	93	70	52	28	20	15	708MMBO*
First Discovery								(16)	(64)	120	132	100	84	80	80	80	80	65	50	37	28	20	15				354MMBO*
Second Discovery											(12)	(64)	120	132	100	84	80	80	80	80	65	50	37	28	20	15	354MMBO*
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)								(4)	(76)	(150)	198	200	230	238	400	400	400	400	400	400	400	240	200	170	162		1620BCFG*

1. (X) = gas discovery

*Total Cumulative Production

Exhibit A 23

Exhibit A-24
Development Alternative 10:
Naval Petroleum Reserve No. 4

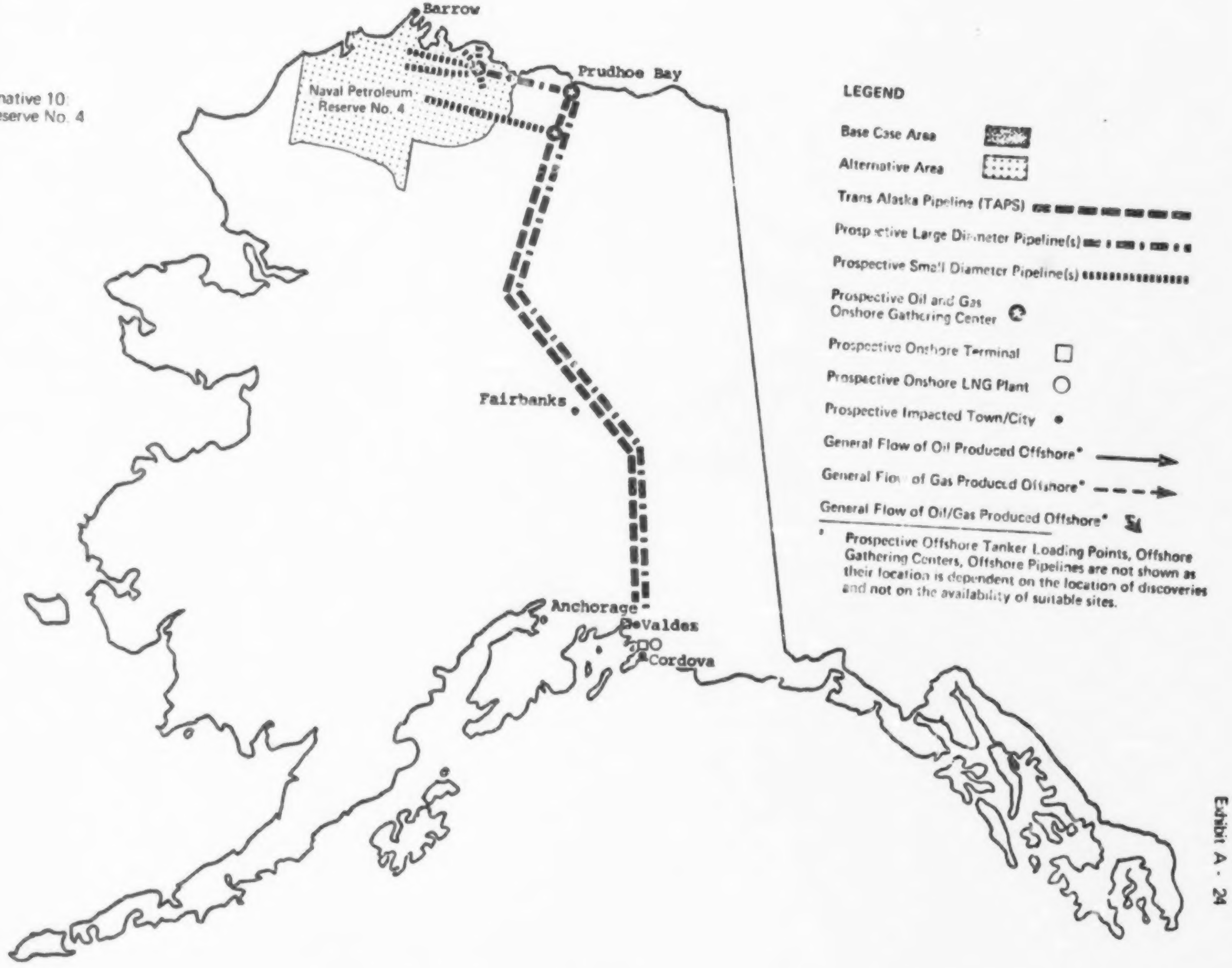

Barrow
Prudhoe Bay
Naval Petroleum Reserve No. 4
Fairbanks
Anchorage
Valdez
Cordova
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-25

Development Alternative 10–Naval Petroleum Reserve No. 4

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)	1	3	3	5	5	5	5	5	5	5	5	4	2	2	2	2	4	4	4	4	2	4	2				83
Discovery				x^1		x^1			x^1								$x^2(x)^2$		$x^2(x)^2$		$x\ (x)^2$						
Delineation (No. of Wells)					2	3	2	3		2	3							4		4		4					27
Development – Oil																											
Platforms																											
Wells – Total							16	32	80	72	96	72	64	80	40	32	16		8	16	32	16	32	16	24		744
First Discovery							16	32	64	40	32	16															200
Second Discovery									16	32	64	40	32	16													200
Third Discovery												16	32	64	40	32	16										200
Fourth Discovery																			8	16	24						48
Fifth Discovery																					8	16	24				48
Sixth Discovery																							8	16	24		48
Development – Gas																											
Platforms																											
Wells									8	16	32	16	32	16	24					8	24	16	8	16			216
Production – Oil (MBOPD)																											
Total							(48)	(144)	(382)	456	600	1056	1080	1000	1336	1400	1400	1280	1200	1200	1148	1073	966	697	690	396	6196MMBO*
First Discovery							(48)	(144)	(388)	456	600	600	480	400	400	400	400	400	400	400	300	225	170				2055MMBO*
Second Discovery									(48)	(144)	(388)	456	600	600	480	400	400	400	400	400	400	400	300	225	170		2055MMBO*
Third Discovery												(48)	(144)	(388)	456	600	600	480	400	400	400	400	400	400	400	300	1911MMBO*
Fourth Discovery																			(8)	(24)	48	48	48	24	24	24	79MMBO*
Fifth Discovery																					(8)	(24)	48	48	48	24	61MMBO*
Sixth Discovery																							(8)	(24)	48	48	35MMBO*
Production – Gas (MMCFGPD)							(64)	(192)	(480)	(640)	780	1080	1560	1560	2340	2340	2340	2340	2340	2340	2680	1980	1340	1460	960	960	10097BCFG*

1. Discovery contains both oil and gas 2. Small fields discovered in second phase of exploration

*Total Cumulative Production

Exhibit A-26
Development Alternative 11
Chukchi Sea

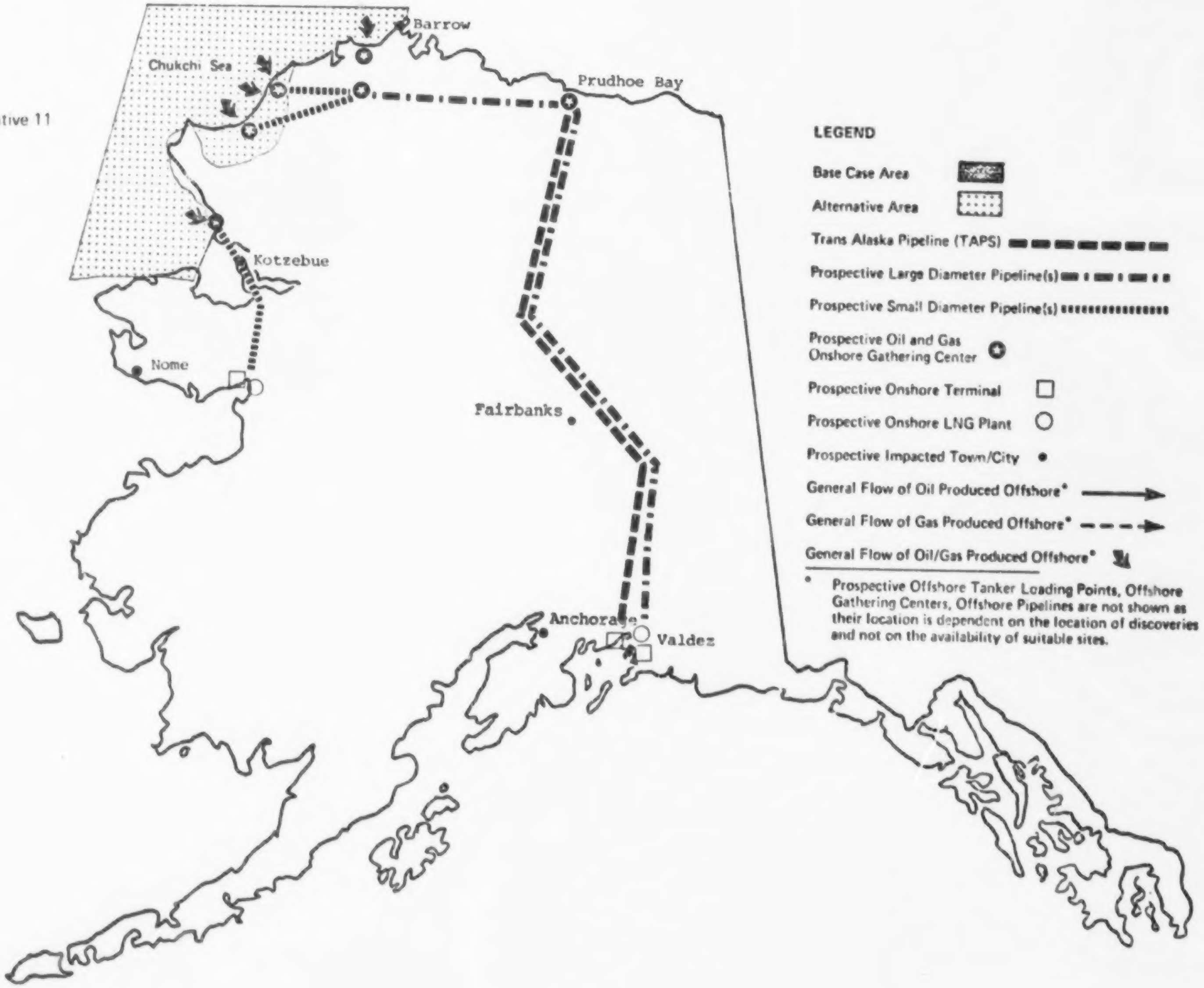

Barrow
Chukchi Sea
Prudhoe Bay
Kotzebue
Nome
Fairbanks
Anchorage
Valdez
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal
Prospective Onshore LNG Plant
Prospective Impacted Town/City
General Flow of Oil Produced Offshore*
General Flow of Gas Produced Offshore*
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A - 26

Exhibit A-27

Development Alternative 11—Chukchi Sea

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)						2	2	2	4	4	8	12	12	16	16	16	16	16	12	12	12	8	6	2	2		180
Discovery								x^2	(X)	(X)	X	(X)	X	(X)	X	X		(X)		X	(X)						
Delineation (No. of Wells)									2	5	5	5	5	5	5	5	5	3	2	3	2	5	3				60
Development – Oil																											
Platforms										1	2		1	2	4	2	5	5	8	3		1	2	3			39
Wells – Total										12	24	20	14	18	40	44	58	68	98	86	50	18	18	34	26	12	640
First Discovery										12	24	20	8														64
Second Discovery													6	18	34	26	12										96
Third Discovery															6	18	34	26	12								96
Fourth Discovery																	12	36	88	52	24						192
Fifth Discovery																		6	18	34	26	12					96
Sixth Discovery																						6	18	34	26	12	96
Development – Gas																											
Platforms													1	3	6	5	4	2	3		1	2	3	1	2	3	36
Wells													6	24	58	78	78	56	46	26	18	18	34	32	30	34	538
Production – Oil (MBOPD)																											
Total										(24)	(72)	112	128	72	306	410	680	668	1128	1421	1562	1342	1113	1209	1249	1219	4625MMBO*
First Discovery										(24)	(72)	112	128	72	64	64	64	64	64	57	50	38	29	22	17		308MMBO*
Second Discovery													(24)	(96)	232	336	384	268	216	192	192	192	192	163	128	96	946MMBO*
Third Discovery															(24)	(96)	232	336	384	268	216	192	192	192	192	163	864MMBO*
Fourth Discovery																	(49)	(192)	464	672	768	536	432	384	384	384	1469MMBO*
Fifth Discovery																		(24)	(96)	232	336	384	268	216	192	192	664MMBO*
Sixth Discovery																						(24)	(96)	232	336	384	374MMBO*
Production – Gas (MMCFGPD)													(48)	(192)	464	1136	1904	2208	2768	2976	3072	3072	3536	3648	3440	3136	11446BCFG*

1 (X) = gas discovery 2. Discovery Onshore, Pt. Lay–Cape Lisburne

*Total Cumulative Production

Exhibit A-28

Development Alternative 12
Arctic Wildlife Range

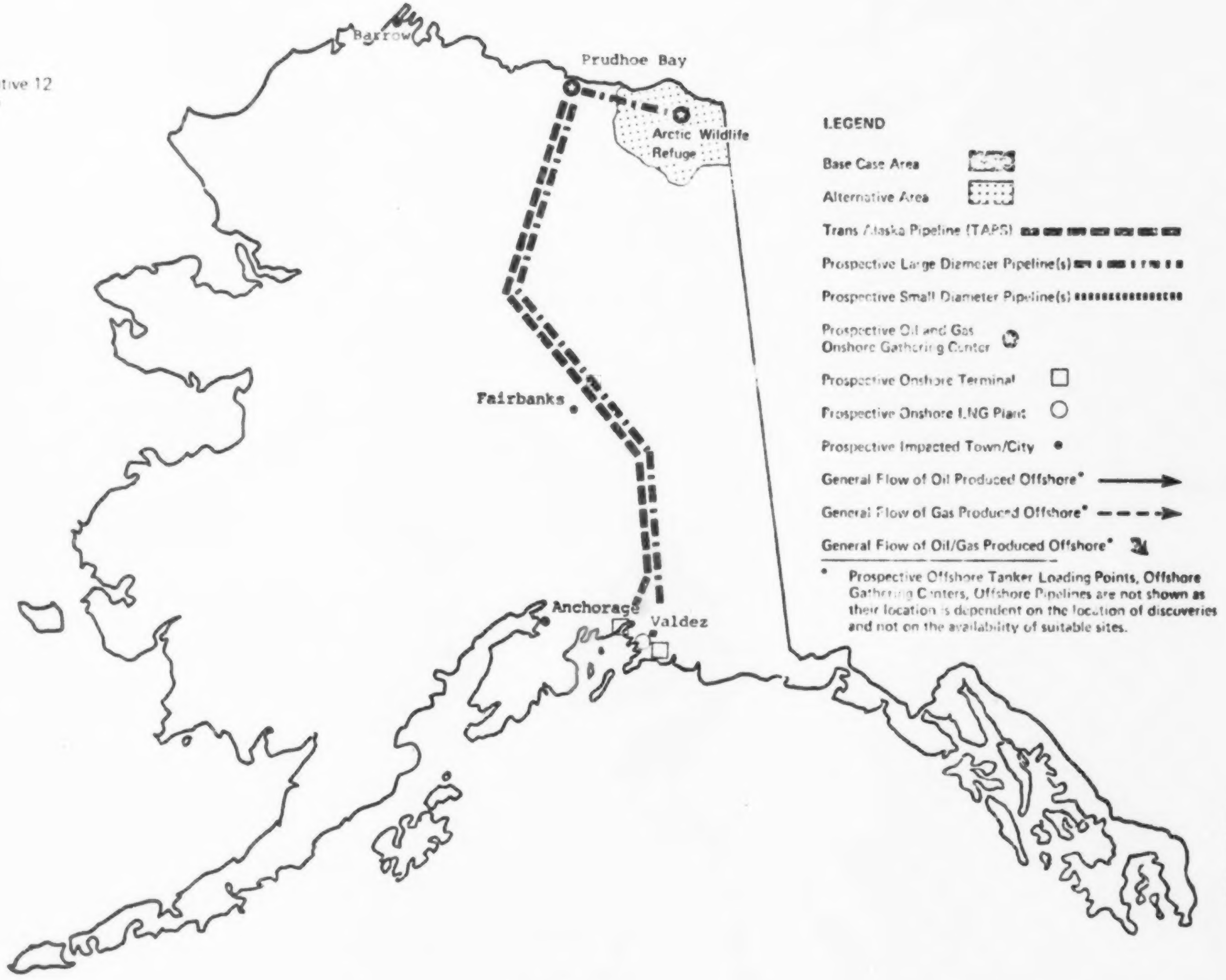

Barrow
Prudhoe Bay
Arctic Wildlife Refuge
Fairbanks
Anchorage
Valdez
LEGEND
Base Case Area
Alternative Area
Trans Alaska Pipeline (TAPS)
Prospective Large Diameter Pipeline(s)
Prospective Small Diameter Pipeline(s)
Prospective Oil and Gas Onshore Gathering Center
Prospective Onshore Terminal □
Prospective Onshore LNG Plant ○
Prospective Impacted Town/City ●
General Flow of Oil Produced Offshore* →
General Flow of Gas Produced Offshore* - - →
General Flow of Oil/Gas Produced Offshore*
* Prospective Offshore Tanker Loading Points, Offshore Gathering Centers, Offshore Pipelines are not shown as their location is dependent on the location of discoveries and not on the availability of suitable sites.

Exhibit A-29

Development Alternative 12–Arctic Wildlife Range

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	Total
Exploration (No. of Wells)											1	2	4	4	5	2											18
Discovery													x[1]														
Delineation (No. of Wells)															2	3											5
Development – Oil																											
Platforms																											
Wells – Total																	20	30	50	50	50						200
First Discovery																	20	30	50	50	50						200
Second Discovery																											
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Development – Gas																											
Platforms																											
Wells																		25	25	25	25						100
Production – Oil (MBOPD)																											
Total																											
First Discovery																	(60)	(150)	(300)	450	600	600	516	443	400	400	1244MMBO*
Second Discovery																	(60)	(150)	(300)	450	600	600	516	443	400	400	1244MMBO*
Third Discovery																											
Fourth Discovery																											
Fifth Discovery																											
Sixth Discovery																											
Production – Gas (MMCFGPD)																		(250)	(500)	750	1000	1000	1000	1000	1000	1000	2463 BCFG*

[1] Discovery contains both Oil and Gas.

*Total Cumulative Production

ECONOMIC IMPACT METHODOLOGY

To translate oil and gas development and related facilities assumptions into forecasts of primary and secondary economic impacts on Alaska, we developed a methodology that used an econometric model. We explain the model before discussing how we applied the model to project primary and secondary economic impacts.

A - DESIGN OF THE ECONOMETRIC MODEL

The econometric model was developed originally by the Human Resources Planning Institute (HRPI) for the Man in the Arctic program at the Institute of Social, Economic, and Government Research (ISEGR). The model was used to project the impact of trans-Alaskan pipeline construction on the Alaskan economy.* Since that time, the model has been refined and updated by HRPI under contract to the United States Department of Labor.** It is this second version we have used in this study.

We selected this particular model for its credibility; it has been used before by the Alaskan government and interested parties to forecast the impact of oil and gas development. It was selected also for its level of detail; it is one of the most detailed econometric descriptions ever developed on a subnational basis, breaking down the Alaskan economy into 16 employment categories and 2 unemployment categories.*** In addition, it was more cost effective to use this model than to design a new economic model that would necessarily be smaller, less complex, and less accurate.

The model developed by HRPI is an economic base model. An economic base model assumes a regional (state) economy is composed of two parts. One part is export oriented (exogenous demand) and exists solely as a result of the region's natural resources or of decisions made outside the region; the components of this segment of the economy are called basic industries (e.g., federal defense spending or oil and gas extraction),

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* See Alaskan Pipeline Report, Institute of Social, Economic, and Government Research, University of Alaska, 1973.

** A much more detailed description can be found in Manpower and Employment Impact of the Trans-Alaska Pipeline, Vol. II, Technical Report, Human Resources Planning Institute and Urban and Rural Systems Associates, November 1974.

*** Apparently the model loses little statistical significance in going to this level of detail. The R^2 are around 0.9.

and these industries predominantly do not serve local needs. Another part caters primarily to local needs (endogenous demand) and rises and falls with the size and structure of the basic industries; the components of this segment are termed nonbasic industries (e.g., wholesale trade, retail trade, and services).

The HRPI model considers six basic industries, six nonbasic industries, and two industries that are usually nonbasic but for purposes of analysis are considered to have both basic and nonbasic characteristics. (See Exhibit B-1.) The basic industries, since they are assumed to respond to exogenous demand, are forecast independent of and outside the model. For example, their employment forecasts are based on forecasts for the entire national industry in which they operate (e.g., fish processing is viewed within the national fish industry) and estimates of informed Alaskan industry sources. Forecasts for nonbasic industries are based on levels of employment in the basic industries, other nonbasic industries, and related social variables (state and local expenditures, population, unemployment).

The model operates on a calendar-quarter-by-calendar-quarter basis, using last quarter's results and seasonality factors to project current-quarter results.* The sequence of steps in the model is shown in Exhibit B-2. Starting with initial values for the variables and with basic industry forecasts, nonbasic industry employment is forecast. Next, unemployment and civilian work force projections are developed. Finally, total population is calculated from military population forecasts and dependency ratios. From that point, the model cycles to the next time period.

To operate this model, two sets of assumptions are needed.

1. Employment forecasts for the basic industries. For each of the basic industries, we have used the HRPI employment forecasts through 1980, extending them on the basis of our own estimates through 1990. (Exhibit B-3 shows the forecasts used.)

2. Mathematical relationships for the nonbasic industries. The mathematical relationships developed by HRPI to forecast the nonbasic industries were based on historical data from 1961 to the present. The relationships that were developed by means of regression analysis were chosen on the basis of "goodness of fit" and economic sense. The interrelationships of each nonbasic industry forecast with other nonbasic industries and with basic industries are shown in Exhibit B-4.

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* An annual model would have been sufficient for our purposes. However, given the availability of the HRPI model, we calculated quarterly results and presented them in an annualized format.

B - APPLICATION OF THE MODEL

To gauge the impact on the Alaskan economy of further oil and gas development, we applied the HRPI model to the scenarios used in this study. To facilitate an understanding of the results of the application, we discuss below: (1) the interface between the HRPI model and the development scenarios selected for this effort; (2) the development assumptions that interfaced with the HRPI model; and (3) how the results of the statewide model were disaggregated to the regional level.

HRPI MODEL/DEVELOPMENT SCENARIO INTERFACE

The model, as constructed, forecasts state employment in the absence of future oil and gas development. But *with* future oil and gas development, these base forecasts must be adjusted to account for more employees than were planned for under the base assumptions. For example, the model assumes contract construction employment is based on population, federal government employment, and seasonal factors. The construction of an oil pipeline, however, is considered to be *incremental* construction employment, *over and above* that required to satisfy normal requirements. These additional construction workers do have an effect - e.g., in terms of construction supplies and services - on the economy. These effects are simulated by adding, in the appropriate time periods, this exogenous estimate of pipeline construction. (See Exhibit B-5 for an illustration of the technique.) The model then uses this adjusted estimate of construction employment as an independent variable in calculating the secondary effects on the nonbasic industries.

This technique is used to simulate the effects of each state of petroleum, gas, and facilities development and operation. First, for each development scenario, the number of incremental employees in each industrial category is aggregated. Next, the number of incremental employees is added to the forecasting equation used for that industry.* Lastly, the model is run to calculate the effects of this incremental activity on the nonbasic industries. Exhibit B-6 shows the stages of petroleum development for which employment estimates have been made, as well as industry designation in the model to which these incremental employees are added.

The use of an economic base model in this study did present several problems, however. First, the model was designed originally for shorter term (to 1980) impact analysis of the Alyeska pipeline. Second, the model tends to preserve the structure of the Alaskan economy as it existed in the 1960s and early 1970s. Since the economy at that time had a high service component, the model continues to predict high service components. It is reasonable to expect that the economic structure will change over time, probably to proportionately lower service components. We have not modified the model to reflect these changes because of time and resource constraints.

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* For basic industries, incremental employees are added to the forecast; for nonbasic industries, incremental employees are added to the forecasting equation.

HRP1 MODEL/DEVELOPMENT ASSUMPTIONS INTERFACE

To carry out the above procedure, we had to develop employment assumptions for: (1) exploration; (2) development; (3) production; (4) transportation; (5) processing; and (6) terminal storage. Each of these sets of assumptions is spelled out in the sections that follow.

Exploration

The oil and gas exploration process involves the operation of seismic exploration vessels and exploratory drilling rigs. As many as 10 seismic exploration vessels may be active in an offshore area at one time, depending on the expanse of the area. These vessels generally carry a crew of 30 and occasionally dock on shore. In addition, we have assumed the crew members of these vessels will probably reside in an onshore location, convenient to the region in which exploratory activity is taking place, for the duration of their employment.

Exploratory drilling rigs, which can drill an average of four wells per year, are moved into an outer continental shelf (OCS) area after seismic exploration has indicated the presence of oil or gas. From our previous work with the Council on Environmental Quality (CEQ), we have assumed that each rig will employ a crew of approximately 50 persons at one time.* We have also assumed rig crews will rotate on a 14-days-on/7-days-off schedule. And we have assumed that approximately 100 persons will be employed in onshore support operations for each exploratory rig.**

Development

We assumed that platforms used for development drilling and production of Alaska oil and gas will most likely be fabricated elsewhere (e.g., Japan or West Coast), and thus will not affect employment in Alaska. However, the actual drilling of development wells will involve a specialized crew, some of whom will be temporarily employed for specific purposes (e.g., electricians, mechanics). Specifically, we assumed that approximately 50 personnel will be employed on a development platform at one time, while 100 people will be required onshore to support offshore development occurring on one platform. Three to 4 years is the length of time usually required to drill the maximum number of wells (24-32) a platform can support.

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* The crew would include geologists, engineers, and other specialized labor (e.g., contract welders).

** Onshore personnel include dock workers and other dockside support, helicopter pilots, and supply personnel. Some economies of scale may be possible with these personnel since they may serve more than one rig. We have not taken this into account; to that extent, the impacts are overestimated.

Production

The typical production platform can support 24 wells, each of which requires approximately four personnel, offshore and onshore, for operation and maintenance. However, few people are utilized on the platform at any one time; rather, onshore and transportation support service personnel comprise a larger percentage of the total work force than in exploration, delineation, or development. Platform personnel include a monitor to control the equipment, electricians and mechanics to service periodically the specialized equipment on the platform, general maintenance staff to perform painting and repair tasks, and special crews to rebore the wells periodically.

Transportation

Oil pipeline - offshore. Pipelines are normally used to transport oil produced offshore to shipment points. It is assumed that pipelines will be used more extensively in Alaska than in other offshore-production areas because of the greater distances and more unfavorable weather conditions. As a result, we have further assumed, from research of industry sources conducted for our study for the CEQ, that 750 workers will be employed for 3-4 years for construction of each 100 miles of a required 36-inch underwater oil pipeline.

Oil pipeline - onshore. Pipelines will also be needed to transport oil produced from wells onshore and from onshore recovery areas to accessible terminal locations or processing centers. According to the Department of the Interior's Final Environmental Impact Statement, Proposed Trans-Alaska Pipeline System and Volume II: Technical Report of Human Resources Planning Institute's Manpower and Employment Impact of TAPS, the construction manpower schedule of an 800-mile, onshore oil pipeline will be: Year 1 - 6,200 (average annual employment); Year 2 - 10,600; and Year 3 - 9,100. The pipeline will be constructed in 13 spreads, varying from 60 miles to 100 miles each. Each spread will require 600-800 construction personnel. Operation and maintenance of the completed pipeline will require appoximately 206 men at one permanent camp and several employees at each of the 12 pump stations located at intervals along the pipeline.

Using TAPS as typical of onshore pipelines in Alaska, we assumed that each 100 miles of 48-inch onshore pipeline will require an average of 775 construction employees in the first year of construction, 1,325 the second year, and

1,150 in the third year. Operation and maintenance per pipeline will require 25 employees in a permanent camp, along with eight online employees for each 100 miles of pipe.*

Gas pipeline. In the El Paso Federal Power Commission (FPC) submission, gas will be transported across Alaska from inaccessible producing areas to shipment or processing locations. Construction of the 810-mile pipeline necessary to transport this gas, as proposed by the El Paso Alaska Company, will require 5 years. The construction employment estimates, according to the *Application of El Paso Alaska Company for a Certificate of Public Convenience and Necessity*, are: Year 1 - 1,300 (average annual employment); Year 2 - 3,075; Year 3 - 3,375; Year 4 - 1,500; and Year 5 - 1,138. Operation and maintenance of the pipeline, when completed, will require 22 supervisors and technical personnel; 138 persons on duty at one time, including two men at each of the 12 meter stations and one man in charge of dispatching and control; and 37 persons off duty - for a total of 197 employees. Support services (e.g., administrative) will require 71 persons per year for the life of the pipeline.

Shorter Alaskan pipelines (e.g., the proposed Arctic Gas pipeline) will involve considerably lower levels of employment. Depending on the approved route, which could vary from 195 miles to 300 miles across the northeastern region of Alaska, construction could take 1-2 years, and annual average employment could vary from 500 to 700 persons. Operation and maintenance of a pipeline this size could require approximately 46 persons - 39 at the production location and 6 in administrative positions in Anchorage.**

Using the El Paso submission as a typical onshore gas pipeline, we assumed each 100-mile segment of onshore gas pipeline will require an average of 165 construction employees in the first year of construction, 385 in the second year,

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* Recently, however, announced employment estimates for TAPS construction have reached 20,000 people compared with the 10,000 or so used here. If this reflects a basic need for far more construction personnel for Alaskan construction, all employment estimates for pipeline construction are understated. However, TAPS is the first Alaskan pipeline of such magnitude, and learning curve effects may reduce employment estimates.

** See *Arctic Gas Environmental Report*, 1974, and *Manpower and Employment Impact of TAPS*, Human Resources Planning Institute, 1974.

420 in the third, 185 in the fourth, and 140 in the fifth.* Operation will require in excess of 22 supervisors for the total pipeline and 22 operations and maintenance personnel for each 100-mile segment.

Gas processing. Gas-processing plants will be required if gas is to be used in Alaska. Therefore, assuming a processing plant of 450 MMCFGPD throughput capacity, about 120 construction personnel will be required for approximately 24 months.** Operation and maintenance of a processing plant this size will involve 55 employees initially, declining to 26 by 2000.

Gas - LNG. LNG plants will be needed if gas is to be transported to distant markets. Therefore, using the LNG plant (3,030 MMSCFPD output) proposed in conjunction with the El Paso pipeline as a model, we have assumed a 5-year construction schedule, as follows: Year 1 - 120 (average annual employment); Year 2 - 2,225; Year 3 - 4,375; Year 4 - 2,675; Year 5 - 700. On completion of the plant, annual employment is anticipated to be 272 for operation and maintenance and 37 for support.***

Terminal Storage

Oil. Onshore marine terminals will be required in Alaska to handle the shipment of oil and gas produced in the state to other markets. The terminal at the conclusion of TAPS (1.2 MMBOPD) will require 2 years to construct, during which time annual employment will run 400-500.

Gas. The marine terminal associated with the El Paso pipeline and LNG plant (3,030 MMSCFPD output) is expected to be constructed in 3 years. It is anticipated that the average annual employment requirements for construction will be: Year 1 - 30; Year 2 - 95; and Year 3 - 120. Operation and maintenance of the terminal will be handled by personnel employed by the associated LNG plant and carrier fleet. Support of the terminal activity will involve 36 persons.

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* While this final report was being produced, El Paso reduced their employment estimates.

** See Facilities Task Force Report, Project Independence Blueprint, Federal Energy Administration, 1974.

*** During preparation of this final report, El Paso was in the process of revising these estimates.

> The proposed LNG carrier fleet will consist of 11 ships, each with a capacity of 165,000 cubic meters. Each carrier will be staffed with 10 officers and 25 crewmen; a total carrier fleet crew of 578 is anticipated (double the on-duty crew of 385) to allow for crew rotation, vacations, leaves, and personnel turnover. We assumed that 15 percent of the crew will reside in Alaska. Administrative support of the fleet is expected to total 58 persons.*

Using these assumptions, we developed employment estimates for each of the five major components of the oil development process, apportioning them to the areas in which they will occur. (See Exhibits B-7 through B-18.)

DISAGGREGATION OF RESULTS TO REGIONAL LEVEL

The HRPI model, as developed, shows employment and changes in employment for the state as a whole. It can disaggregate this total to seven regions** by using each region's historical proportion of the state total. We believe this disaggregation, while reasonable for small changes in employment resulting from oil and gas development, is not adequate for the much larger employment changes, especially when they occur in remote areas. For example, a large influx of development personnel to Kotzebue will generate a demand for secondary development. With the HRPI model, this demand would be proportioned to all other areas on the basis of historical economic activity.

To cope with this "inaccuracy," we have altered the HRPI model somewhat. Specifically, for each industry in the model and for each election district, we evaluated what fraction of incremental state economic activity resulting from incremental direct oil and gas activity is likely to result in the local area. (For example, if oil development in Kotzebue should result in a need for 200 additional service workers in the state as a whole, we would estimate what fraction of that 200 would occur in Kotzebue and what fraction would occur in the rest of the state.) To do this, we examined the structure of employment in each of the industries used in the model. Next, looking at the current characteristics of an election district's economy, population size, access, and climate, we estimated which subindustries could be considered purely local to that area and which are likely to be supplied from outside. (The results of this judgmental analysis are shown in Exhibits B-19 through B-29). After calculating the local incremental activity for each election district, the remainder was assumed to be spread among the other election districts in proportion to their historical shares of state employment in that industry.

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* Application of the El Paso Alaska Company for a Certificate of Public Convenience and Necessity, 1974.

** These seven regions are generally aggregates of Alaskan election districts.

Exhibit B-1

ECONOMETRIC MODEL OF THE ALASKAN ECONOMY

Basic Industries

- Communications and Utilities
- Mining
  - Petroleum
  - Other
- Manufacturing
- Federal Government
- Native Services
- Military

Combination Industries

- Construction
  - Pipeline
  - Other Construction
- Transportation
  - Pipeline
  - Other Transportation

Nonbasic Industries

- State and Local Government
- Retail Trade
- Wholesale Trade
- Services
- FIRE*
- Noncategorized**

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* Finance, Insurance, and Real Estate.

** Includes Agriculture.

Exhibit B-2

Alaska Statewide Employment Model

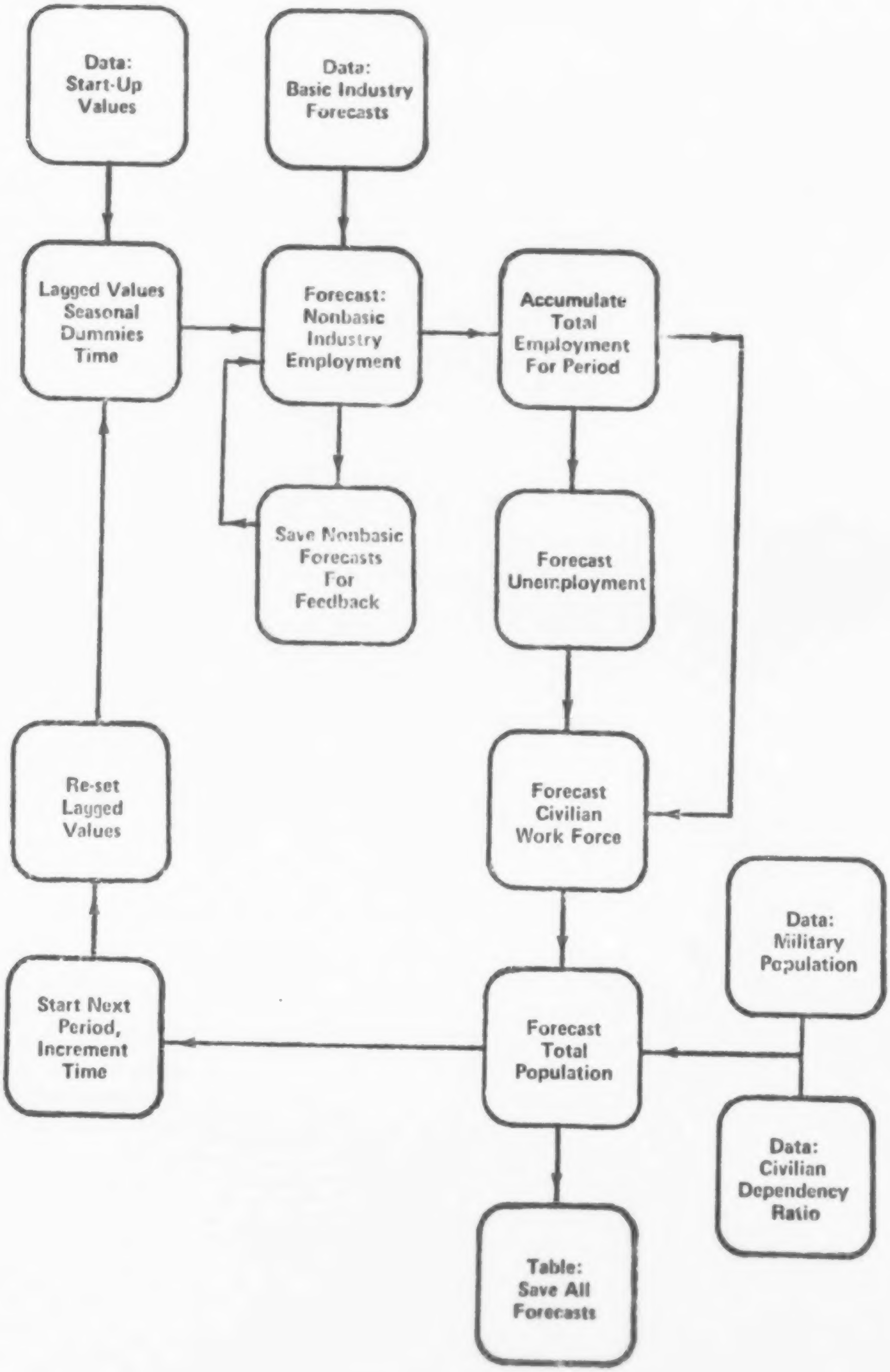
Data: Start-Up Values
Data: Basic Industry Forecasts
Lagged Values Seasonal Dummies Time
Forecast: Nonbasic Industry Employment
Accumulate Total Employment For Period
Save Nonbasic Forecasts For Feedback
Forecast Unemployment
Re-set Lagged Values
Forecast Civilian Work Force
Data: Military Population
Start Next Period, Increment Time
Forecast Total Population
Data: Civilian Dependency Ratio
Table: Save All Forecasts

Exhibit B-3

BASIC INDUSTRY EMPLOYMENT FORECASTS, SELECTED YEARS

Industry	1973	1980	1985	1990
Mining*	2,400	2,900	3,200	3,400
Communications and Utilities	3,600	3,900	4,000	4,200
Federal Employment	17,200	17,700	17,900	18,200
Manufacturing	8,400	10,700	12,450	14,200
Native Services	50	575	700	825
TAPS Operation and Maintenance	---	450	450	450
Military	27,000	27,000	27,000	27,000

---

* Indicator base case activity.

Sources: 1973-1980 estimates were obtained from the HRPI report; 1981-1990 estimates were obtained by our extending the HRPI estimates through 1990.

Exhibit B-4-1

NONBASIC INDUSTRY EQUATIONS FROM STEP-WISE REGRESSION PROGRAM

UNEMPLOYMENT
R^2=.951 σ=654.47
1961: I → 1972:IV
DF=41 DW=1.68

−3895.8	+	4282.1S1	+	5034.0S2	+	1507.9S3	+	.0002134 TEMP
(−3.9)*		(10.4)		(4.1)		(1.1)		(4.2)
−21445.4 DELT	+	.576633 UNEM−1	+	BOOM				
(−4.1)		(5.5)						

STATE & LOCAL GOVERNMENT
R^2=.933 σ=1206.63
1961: I → 1972:IV
DF=45 DW=.85

−11373.1	+	.06069255 PLES	+	36.0793 STEX
(−5.7)		(6.0)		(8.7)

TRANSPORTATION
R^2=.956 σ=217.99
1961 I → 1972:IV
DF=39 DW=1.42

+684.8	+	237.4S1	−	16.4S2	+	643.8S3	+	.162967 CONS	+	.713466 MING
(1.5)		(1.3)		(−0.1)		(1.6)		(2.7)		(9.6)
+.174706 MFRG	+	.256229 STLO	−	87.39 TIME	+	O/M				
(1.9)		(5.9)		(−4.8)						

RETAIL TRADE
R^2=.980 σ=388.99
1961: I → 1972:IV
DF=40 DW=.85

−12039.8	+	1220.6S1	+	1487.0S2	−	352.6S3	+	.362468 MFRG
(3.0)		(2.7)		(2.1)		(−0.4)		(2.2)
+.180601 MING	+	.064513 POPL−1	+	15.1 TIME				
(1.6)		(3.8)		(0.45)				

SERVICES
R^2=.995 σ=203.9
1961: I → 1972:IV
DF=40 DW=1.19

−1926.8	+	783.3S1	+	482.2S2	−	280.1S3	−	49.27 TIME	+	.64438 RETL
(−4.8)		(4.6)		(5.7)		(−1.7)		(−3.6)		(7.0)
+.16094 CONS	+	.34271 STLO	+	NASR						
(3.2)		(7.2)								

WHOLESALE TRADE
R^2=.981 σ=98.70
1961: I → 1972:IV
DF=42 DW=1.3

−217.7	+	134.6S1	+	61.7S2	+	32.0S3	+	.143862 MING	+	.236687 RETL
(−3.8)		(3.3)		(1.5)		(0.8)		(5.4)		(26.7)

---

* Figures in parentheses under the coefficients are T values. Variables without T values were not applicable to the historic period 1960–1972, and thus are exogenous to the regression analysis.

Exhibit B-4-2

NONBASIC INDUSTRY EQUATIONS FROM STEP-WISE REGRESSION PROGRAM

(Continued)

CONSTRUCTION
$R^2=.948$ $\quad \sigma=555.76$
1961 I → 1972:IV
DF=42 $\quad$ DW=1.16

$$-\underset{(-6.9)}{14067.6} - \underset{(-5.8)}{1415.3S1} + \underset{(3.9)}{1046.3S2} + \underset{(10.4)}{2719.0S3} + \underset{(9.8)}{.034313\ FLES}$$

$$+.59379\ FEDL + PIPE$$

FINANCE, INSURANCE, REAL ESTATE
$R^2=.957$ $\quad \sigma=127.68$
1961 I → 1972:IV
DF=41 $\quad$ DW=0.86

$$-\underset{(-11.6)}{3742.7} + \underset{(7.3)}{423.8S1} + \underset{(2.5)}{399.3S2} - \underset{(-0.7)}{174.1S3} + \underset{(4.1)}{.229743\ COMU}$$

$$+\underset{(2.0)}{.107405\ MFRG} + \underset{(8.4)}{.016999\ POPL-1}$$

NON-CATEGORIZED
$R^2=.884$ $\quad \sigma\ 625.03$
1961 I → 1972:IV
DF=42 $\quad$ DW=.60

$$+\underset{(35.8)}{9717.0} - \underset{(-3.5)}{903.2S1} + \underset{(2.5)}{649.1S2} + \underset{(9.9)}{2538.9S3} + \underset{(7.5)}{2481.6\ DUM65}$$

$$+\underset{(8.6)}{56.81\ TIME}$$

Exhibit B–4–3

VARIABLE ABBREVIATION LIST

BOOM	Unemployed "boomers"
COMU	Communications and Utilities
CONS	Construction
DELT	(TEMP – TEMP (–1)/TEMP (–1)
DEPN	Ratio of Civilian Population to Civilian Work Force
DUM65	Dummy Variable = 1 in 1965, = 0 in all other years
FEDL	Federal Government
FIRE	Finance, Insurance, Real Estate
MFRG	Manufacturing
MING	Mining
MPOP	Military Population
NASR	Native Services
NONC	Noncategorized
O/M	Pipeline Operation and Maintenance
Pipe	Pipeline Construction
PLES	POPL–1 less PIPE
POPL	Total Population
RETL	Retail Trade
S1	Seasonal Dummy Function for Quarter 1
S2	Seasonal Dummy Function for Quarter 2
S3	Seasonal Dummy Function for Quarter 3
SERV	Services
STEX	State Expenditures (In Millions of 1970 Dollars)
STLO	State and Local Government
TEMP	Total Employment
TIME	Quarterly Counter (Starts in Qt. 1 of 1960)
TPOP	Total Population
TRAN	Transportation
UNEM	Unemployed
WHOL	Wholesale Trade
WORK	Total Civilian Work Force

Note: Lagged values, which use the value for the preceding quarter, have abbreviations followed by –1– e.g., POPL–1, TEMP–1, UNEM–1.

Exhibit B-5

HYPOTHETICAL DEVELOPMENT OF INPUT DATA FOR USE IN MODEL

(Employment Forecast)

Industry	Calendar Quarter I	II	III	IV	I	II	III	IV	I	II	.... etc.
Construction											
Base Case	20	20	20	30	30	30	30	25	25	25	
Pipeline A			15	15	15	15	15				
Pipeline B				10	10	10	10	10	10		
Pipeline C									5	5	
New Total Scenario Construction Employment	**20**	**20**	**35**	**55**	**55**	**55**	**55**	**35**	**40**	**30**	

Exhibit B-6

Employment Estimates

Stages in Petroleum Development	Industry
Development	
Exploration	Mining
Development	Mining
Production	Mining
Processing	
Refining	
· Construction	Construction
· Operation	Manufacturing
Gas Processing and Liquefaction	
· Construction	Construction
· Operation	Manufacturing
Transportation-Pipeline	
Construction	Construction
Operation and Maintenance	Transportation
Storage-Terminal	
Construction	Construction
Operation and Maintenance	Wholesale Trade

Primary Employment Assumptions with Oil and Gas Development: Prudhoe Private

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
VALDEZ	Mining																
	Construction				400	500											
	Transportation																
	Wholesale						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
OTHER	Mining	1200	1425	1200	1525	1400	2684	3866	4488	3775	3650	2850	4100	4940	3730	2970	3010
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
TOTAL ALASKA	Mining	1200	1425	1200	1525	1400	2684	3866	4488	3775	3650	2850	4100	4940	3730	2970	3010
	Construction	--	--	--	400	500	--	--	--	--	--	--	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
	Wholesale	--	--	--	--	--	40	40	40	40	40	40	40	40	40	40	40
	Manufacturing	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Exhibit B-7

Primary Employment Assumptions with Oil and Gas Development: Prudhoe Bay Natural Gas -- El Paso

AREA	[illegible] COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
VALDEZ	Mining																
	Construction				500	[illegible]											
	Transportation																
	[illegible]						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
FAIRBANKS	Mining																
	Construction					391	[illegible]	[illegible]									
	Transportation								178	178	178	178	178	178	178	178	178
	[illegible]																
	Manufacturing																
OTHER	Mining	1200	1425	1200	1525	1400	2916	4362	6137	5652	5023	4805	5230	6190	5020	4010	4050
	Construction					[illegible]	[illegible]	[illegible]									
	Transportation																
	[illegible]																
	Manufacturing																
CORDOVA	Mining																
	Construction			120	2225	4012	7133	[illegible]	2770	820							
	Transportation								178	178	178	178	178	178	178	178	178
	[illegible]								38	36	72	72	72	72	72	72	72
	Manufacturing								309	309	618	618	618	618	618	618	618
	Mining																
	Construction																
	Transportation																
	[illegible]																
	Manufacturing																
TOTAL ALASKA	Mining	1200	1425	1200	1525	1400	2916	4362	6137	5652	5023	4805	5230	6190	5020	4010	4050
	Construction	--	--	120	2725	6360	15095	14525	2770	820	--	--	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	356	356	356	356	356	356	356	356	356
	[illegible]	--	--	--	--	--	40	40	78	76	112	112	112	112	112	112	112
	Manufacturing	--	--	--	--	--	--	--	309	309	618	618	618	618	618	618	618

Exhibit B 8

Exhibit B-9

Primary Employment Assumptions with Oil and Gas Development: Prudhoe Bay Natural Gas – Artic

AREA	Process Component	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
VALDEZ	Mining																
	Construction				400	500											
	Transportation																
	Wholesale																
	Manufacturing						40	40	40	40	40	40	40	40	40	40	40
FAIRBANKS	Mining																
	Construction				38	137	567	682									
	Transportation																
	Wholesale																
	Manufacturing																
OTHER	Mining	1200	1425	1200	1525	1400	2916	4362	6137	5552	5623	4805	5230	6190	5020	4010	4050
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
TOTAL ALASKA	Mining	1200	1425	1200	1525	1400	2916	4362	6137	5552	5623	4805	5230	6190	5020	4010	4050
	Construction				438	637	567	682									
	Transportation																
	Wholesale																
	Manufacturing						40	40	40	40	40	40	40	40	40	40	40

Primary Employment Assumptions with Oil and Gas Development: Gulf of Alaska

AREA	PROCESS COMPONENT	1975	1976	1977	1973	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
VALDEZ	Mining																
	Construction				400	500											
	Transportation																
	Wholesale						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
FAIRBANKS	Mining																
	Construction					334	2674	2324									
	Transportation								178	178	178	178	178	178	178	178	178
	Wholesale																
	Manufacturing																
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
OTHER	Mining	1212	1625	1550	1837	1756	3447	5031	7065	6507	6622	5995	6420	7385	6166	5185	5150
	Construction				20	1205	7423	6405	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
CORDOVA	Mining																
	Construction			120	2225	4692	6333	6388	2770	820							
	Transportation								178	178	178	178	178	178	178	178	178
	Wholesale								36	36	72	72	72	72	72	72	72
	Manufacturing								309	309	618	618	618	618	618	618	618

Exhibit B-10-1

Primary Employment Assumptions with Oil and Gas Development: Gulf of Alaska (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
TOTAL ALASKA	Mining	1237	2025	2250	2612	2469	4510	6368	8912	8417	8620	8375	8800	9775	8459	7535	7351
	Construction	--	--	120	2685	7473	17900	16301	4096	1924	873	384	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	356	356	356	356	356	356	356	356	356
	Wholesale	--	--	--	--	--	40	40	76	106	142	142	187	187	187	187	187
	Manufacturing	--	--	--	--	--	--	--	309	624	933	933	1074	1074	1074	1074	1074
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Exhibit B-10-2

Primary Employment Assumptions with Oil and Gas Development: Beaufort

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	231	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
VALDEZ	Mining																
	Construction				400	500	500	505	884	767							
	Transportation										87	87	87	87	87	87	87
	Wholesale						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
FAIRBANKS	Mining																
	Construction					554	3187	3890	2014	1720							
	Transportation								178	178	383	383	383	383	383	383	383
	Wholesale																
	Manufacturing																
CORDOVA	Mining																
	Construction			120	2225	4863	7303	8868	4467	1573							
	Transportation								178	178	296	296	296	296	296	296	296
	Wholesale								36	36	110	110	110	110	110	110	110
	Manufacturing								309	624	798	798	798	798	798	798	798
OTHER	Mining	1812	2525	2525	3762	4306	6622	9050	10849	10194	10557	10005	9783	10996	10227	9363	8212
	Construction				20	1760	8706	7971	5476	4668	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152

Exhibit B-11-

Primary Employment Assumptions with Oil and Gas Development: Beaufort (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
TOTAL ALASKA	Mining	1837	2925	3225	4487	5019	9508	10387	12696	12104	12555	12385	12163	13386	12520	11713	10413
	Construction	--	--	120	2865	8413	21066	22418	13724	9464	873	384	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	356	356	767	767	767	767	767	767	767
	Wholesale						40	40	76	106	180	180	225	225	225	225	225
	Manufacturing	--	--	--	--	--	--	--	309	939	1103	1103	1244	1244	1244	1244	1244
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Exhibit B-11-2

Primary Employment Assumptions with Oil and Gas Development: Bering Sea

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
VALDEZ	Mining																
	Construction				400	500	500	505	884	767							
	Transportation										87	87	87	87	87	87	87
	Wholesale						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
FAIRBANKS	Mining																
	Construction					554	3187	3890	2014	1720							
	Transportation								178	178	383	383	383	383	383	383	383
	Wholesale																
	Manufacturing																
NOME	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
BETHEL	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Exhibit B-12-1

Primary Employment Assumptions with Oil and Gas Development: Bering Sea (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
OTHER	Mining	1812	2826	2529	3767	[illegible]	6077	[illegible]	10840	10194	10557	10205	9763	10796	10227	9363	9212
	Construction				27	1760	[illegible]	7071	6476	4509	291	126					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
CORDOVA	Mining																
	Construction			120	2225	4363	7575	[illegible]	4407	1573							
	Transportation								178	178	292	225	296	296	296	296	296
	Wholesale								36	36	110	110	110	110	110	110	110
	Manufacturing								302	624	798	798	798	798	798	798	798
TOTAL ALASKA	Mining	1837	2000	3375	4767	5019	10145	11061	13602	13748	14292	14331	14340	15716	14800	13483	12909
	Construction	--	--	120	[illegible]	9412	21010	22418	13734	9404	873	304	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	306	[illegible]	767	767	767	767	767	767	767
	Wholesale	--	--	--	--	--	40	40	76	108	180	180	225	225	225	225	225
	Manufacturing	--	--	--	--	--	--	--	302	939	1103	1103	1244	1244	1244	1244	1244
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Exhibit B 12.2

Primary Employment Assumptions with Oil and Gas Development: Lower Cook Inlet

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	909	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
VALDEZ	Mining																
	Construction				400	500	500	505	884	767							
	Transportation										87	87	87	87	87	87	87
	Wholesale						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
FAIRBANKS	Mining																
	Construction					554	3187	3890	2014	1720							
	Transportation								178	178	383	383	383	383	383	383	383
	Wholesale																
	Manufacturing																
NOME	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
BETHEL	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Exhibit B-13-1

Exhibit B-13.2

Primary Employment Assumptions with Oil and Gas Development: Lower Cook Inlet (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
OTHER	Mining	1812	2525	2900	4212	4006	7250	9744	11693	11412	12425	11769	11668	12926	12226	11201	9503
	Construction				20	1760	6756	8471	6736	5743	736	128					
	Transportation																
	Wholesale									30	42	42	57	57	57	57	57
	Manufacturing									105	260	260	307	307	307	307	307
CORDOVA	Mining																
	Construction			120	2225	4863	7303	8863	4467	1573							
	Transportation								178	178	296	296	296	296	296	296	296
	Wholesale								36	36	110	110	110	110	110	110	110
	Manufacturing								219	624	798	798	798	798	798	798	798
TOTAL ALASKA	Mining	1937	3000	3450	5237	6213	10782	11775	14316	14466	16160	16095	16225	17445	16779	15721	14200
	Construction	--	--	120	2685	8413	21026	22918	14084	10539	1318	384	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	356	356	767	767	767	767	767	767	767
	Wholesale	--	--	--	--	--	40	40	76	142	212	212	257	257	257	257	257
	Manufacturing	--	--	--	--	--	--	--	302	939	1256	1258	1309	1309	1309	1309	1309
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Primary Employment Assumptions with Oil and Gas Development:, Kotzebue Sound

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	680	928	955	909	1190	1190	1195	1145	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	680	928	955	909	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
VALDEZ	Mining																
	Construction				400	500	500	505	884	767							
	Transportation										87	87	87	87	87	87	87
	Wholesale						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
FAIRBANKS	Mining																
	Construction					554	3178	3890	2014	1720							
	Transportation								178	178	383	383	383	383	383	383	383
	Wholesale																
	Manufacturing																
BETHEL	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
NOME	Mining		37	75	150	300	319	347	403	572	889	973	1089	1165	1140	1085	1248
	Construction					400	670	675									
	Transportation								10	10	10	10	10	10	10	10	10
	Wholesale								4	4	4	4	4	4	4	4	4
	Manufacturing																

Exhibit B-14-1

Primary Employment Assumptions with Oil and Gas Development: Kotzebue Sound (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
KOTZBUE	Mining	37	75	150	300	337	449	412	644	867	6231	619	497	384	384	384	384
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
CORDOVA	Mining																
	Construction			120	2225	4363	7303	8838	4467	1573							
	Transportation								178	178	296	296	296	296	296	296	296
	Wholesale								36	36	110	110	110	110	110	110	110
	Manufacturing								309	624	798	798	798	798	798	798	798
OTHER	Mining	1812	2525	2600	4212	4906	7259	9744	11693	11412	12425	11769	11663	12926	12226	11201	9503
	Construction				20	1760	8736	8471	6736	5743	736	128					
	Transportation																
	Wholesale									30	42	42	57	57	57	57	57
	Manufacturing									105	260	260	307	307	307	307	307
TOTAL ALASKA	Mining	1874	3000	3600	5537	6556	9408	12187	14990	15333	16783	16714	16722	18030	17183	16105	14584
	Construction	--	--	120	2685	8813	21706	23593	14984	10539	1318	384	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	366	366	777	777	777	777	777	777	777
	Wholesale	--	--	--	--	--	40	40	80	146	216	216	261	261	261	261	261
	Manufacturing	--	--	--	--	--	--	--	309	939	1258	1258	1399	1399	1399	1399	1399
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Exhibit B-14-2

Primary Employment Assumptions with Oil and Gas Development: Bristol Bay

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
VALDEZ	Mining																
	Construction				400	500	500	505	884	767							
	Transportation										87	87	87	87	87	87	87
	Wholesale						40	40	40	40	40	40	40	40	40	40	40
	Manufacturing																
FAIRBANKS	Mining																
	Construction					554	3197	3890	2014	1720							
	Transportation								178	178	383	383	383	383	383	383	383
	Wholesale																
	Manufacturing																
BETHEL	Mining		37	75	150	300	319	347	405	572	869	973	1089	1165	1148	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
NOME	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction					400	670	625									
	Transportation								10	10	10	10	10	10	10	10	10
	Wholesale								4	4	4	4	4	4	4	4	4
	Manufacturing																

Exhibit B-15-1

Primary Employment Assumptions with Oil and Gas Development: Bristol Bay (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
KOTZEBUE	Mining	37	75	150	300	337	449	412	644	867	623	619	497	384	384	384	384
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
BRISTOL BAY	Mining			75	150	300	487	544	750	1068	1158	1276	1227	1411	1221	918	843
	Construction							20	325	630	525	240					
	Transportation																
	Wholesale												6	6	6	6	6
	Manufacturing												155	155	155	155	155
OTHER	Mining	1812	2525	2600	4212	4906	7259	9744	11693	11412	12425	11769	11668	12926	12226	11201	9503
	Construction				20	1760	8736	8471	6736	5743	736	128					
	Transportation																
	Wholesale									30	42	42	57	57	57	57	57
	Manufacturing									105	260	260	307	307	307	307	307
CORDOVA	Mining																
	Construction			120	2225	4863	7303	8868	4467	1573							
	Transportation								178	178	296	296	296	296	296	296	296
	Wholesale								36	36	110	110	110	110	110	110	110
	Manufacturing								309	624	798	798	798	798	798	798	798
ALASKA TOTAL	Mining	1874	3000	3535	5687	6856	11787	12731	15740	16401	17941	17990	17949	19441	18404	17023	15427
	Construction	--	--	120	2685	8813	21766	23563	15309	1469	1843	624	--	--	--	--	--
	Transportation	--	--	--	--	--	--	--	366	366	777	777	777	777	777	777	777
	Wholesale	--	--	--	--	--	40	40	80	146	216	216	267	267	267	267	267
	Manufacturing	--	--	--	--	--	--	--	309	939	1258	1258	1554	1554	1554	1554	1554
	Mining																
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																

Exhibit B-15-2

Exhibit B-16-1

Primary Employment Assumptions with Oil and Gas Development: NPR-4

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
BETHEL	Mining		37	75	150	300	319	347	405	572	869	973	1089	1165	1140	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
NOME	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction					400	670	625									
	Transportation								10	10	10	10	10	10	10	10	10
	Wholesale								4	4	4	4	4	4	4	4	4
	Manufacturing																
KOTZEBUE	Mining	37	75	150	300	337	449	412	644	867	623	619	497	384	384	384	384
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
BARROW	Mining	150	450	450	750	1050	975	1300	1775	2950	3758	4701	4100	4520	5304	3960	4076
	Construction							1382	2580	2355	280	210					
	Transportation										50	50	70	70	70	70	70
	Wholesale																
	Manufacturing																

Primary Employment Assumptions with Oil and Gas Development: NPR-4 (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
FAIRBANKS	Mining																
	Construction					554	3987	4573	3409	3098	280						
	Transportation								173	178	508	508	753	753	753	753	753
	Wholesale																
	Manufacturing																
VALDEZ	Mining																
	Construction				400	500	500	847	1581	1456	3264	140					
	Transportation										212	212	457	457	457	457	457
	Wholesale						40	40	40	40	40	110	110	110	110	110	110
	Manufacturing																
OTHER	Mining	1812	2525	2600	4212	4906	7259	9744	11693	11412	12425	11769	11668	12926	12226	11201	9503
	Construction				20	1760	8736	10177	10224	9187	911	259	--	--	--	--	--
	Transportation																
	Wholesale									30	42	42	57	57	57	57	57
	Manufacturing									105	260	260	307	307	307	307	307
BRISTOL BAY	Mining			75	150	300	487	544	750	1068	1158	1276	1227	1411	1221	918	843
	Construction							20	325	630	525	240					
	Transportation																
	Wholesale												6	6	6	6	6
	Manufacturing												155	155	155	155	155
CORDOVA	Mining																
	Construction			120	2225	4863	7303	8868	4467	1623	775	1511	929	283			
	Transportation								178	178	296	296	296	296	296	296	296
	Wholesale								36	35	110	110	122	122	134	134	134
	Manufacturing								309	624	798	798	898	898	998	998	998
ALASKA TOTAL	Mining	2024	3450	3985	6437	7906	12762	14031	17515	19351	21699	22691	22049	23961	23708	20983	19502
	Construction	--	--	120	2685	8813	21766	27676	23469	19085	6617	2616	929	283			
	Transportation								366	366	1077	1077	1586	1586	1586	1586	1586
	Wholesale						40	40	80	146	216	276	349	349	361	357	353
	Manufacturing								309	939	1258	1258	1654	1654	1754	1754	1754

Exhibit B-16-2

Primary Employment Assumptions with Oil and Gas Development: Chukchi

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	291	128					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
BETHEL	Mining		37	75	150	300	319	347	405	572	869	973	1089	1165	1140	1085	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
NOME	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction					400	670	625									
	Transportation								10	10	10	10	10	10	10	10	10
	Wholesale								4	4	4	4	4	4	4	4	4
	Manufacturing																
KOTZEBUE	Mining	37	75	150	300	337	449	412	644	867	623	619	497	384	384	384	384
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
BARROW	Mining	150	450	450	750	1050	975	1300	1775	2950	3758	4701	4100	4520	5304	3960	4076
	Construction							1382	2580	2355	280	210					
	Transportation										50	50	70	70	70	70	70
	Wholesale																
	Manufacturing																

Exhibit B-17-1

Primary Employment Assumptions with Oil and Gas Development: Chuckchi (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1931	1982	1983	1984	1985	1986	1987	1988	1989	1990
FAIRBANKS	Mining																
	Construction					554	3987	4573	3409	3098	280						
	Transportation								178	178	508	508	753	753	753	753	753
	Wholesale																
	Manufacturing																
BRISTOL BAY	Mining			75	150	300	487	544	750	1068	1158	1276	1227	1411	1221	918	843
	Construction							20	325	630	525	240					
	Transportation																
	Wholesale												6	6	6	6	6
	Manufacturing												155	155	155	155	155
CORDOVA	Mining																
	Construction			120	2225	4863	7303	8868	4467	1623	775	1511	920	283			
	Transportation								178	178	296	296	296	296	296	296	296
	Wholesale								36	36	110	110	122	122	134	134	134
	Manufacturing								309	624	798	798	989	898	998	998	993
VALDEZ	Mining																
	Construction				400	500	500	847	1581	1456	3264	140					
	Transportation										212	212	457	457	457	457	457
	Wholesale						40	40	40	40	40	110	110	110	110	110	110
	Manufacturing																
OTHER	Mining	1812	2525	2600	4212	4906	7259	9744	11693	11412	12425	11769	11668	12926	12226	11201	9503
	Construction				20	1760	8736	10177	10224	9187	911	259					
	Transportation																
	Wholesale									30	42	42	57	57	57	57	57
	Manufacturing									105	260	260	307	307	307	307	307
ALASKA TOTAL	Mining	2024	3450	3985	6437	7906	12762	14031	17515	19351	21699	22691	22049	23961	23708	20983	19502
	Construction	--	--	120	2685	8813	21766	27676	23469	19085	6617	2616	929	283	--	--	--
	Transportation	--	--	--	--	--	--	--	366	366	1077	1077	1586	1586	1586	1586	1586
	Wholesale	--	--	--	--	--	40	40	80	146	216	276	349	349	361	357	353
	Manufacturing	--	--	--	--	--	--	--	309	939	1258	1258	1604	1654	1654	1754	1754

Exhibit B-17-2

Primary Employment Assumptions with Oil and Gas Development: Arctic

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
SEWARD	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	1291	123					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
YAKUTAT	Mining	12	200	350	362	356	531	669	928	955	999	1190	1190	1195	1146	1175	1100
	Construction				20	371	735	592	442	368	1291	123					
	Transportation																
	Wholesale									10	10	10	25	25	25	25	25
	Manufacturing									105	105	105	152	152	152	152	152
BETHEL	Mining		37	75	150	300	319	347	405	572	869	973	1089	1165	1140	1035	1248
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
NOME	Mining		37	75	150	300	319	347	403	572	869	973	1089	1165	1140	1085	1248
	Construction					400	670	625									
	Transportation								10	10	10	10	10	10	10	10	10
	Wholesale								4	4	4	4	4	4	4	4	4
	Manufacturing																
KOTZEBUE	Mining	37	75	150	300	337	449	412	644	867	623	619	497	384	384	384	384
	Construction																
	Transportation																
	Wholesale																
	Manufacturing																
BARROW	Mining	150	450	430	750	1050	975	1300	1775	2950	3758	4701	4100	4520	5304	3960	4076
	Construction							1332	2580	2355	280	210					
	Transportation										50	50	70	70	70	70	70
	Wholesale																
	Manufacturing																

Exhibit B-18-1

Primary Employment Assumptions with Oil and Gas Development: Arctic (Continued)

AREA	PROCESS COMPONENT	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
FAIRBANKS	Mining																
	Construction					554	3987	4573	3409	3098	280						
	Transportation								178	178	508	508	753	753	753	753	753
	Wholesale																
	Manufacturing																
BRISTOL BAY	Mining			75	150	300	437	544	750	1063	1158	1276	1227	1411	1221	918	843
	Construction							20	325	630	525	240					
	Transportation																
	Wholesale												6	6	6	6	6
	Manufacturing												155	155	155	155	155
CORDOVA	Mining																
	Construction			120	2225	4863	7303	8868	4467	1623	775	1511	929	283			
	Transportation								178	178	296	296	296	296	296	296	296
	Wholesale								36	36	110	110	122	122	134	134	134
	Manufacturing								309	624	798	798	898	898	998	998	998
VALDEZ	Mining																
	Construction				400	500	500	847	1581	1456	3264	140					
	Transportation										212	212	457	457	457	457	457
	Wholesale						40	40	40	40	40	110	110	110	110	110	110
	Manufacturing																
OTHER	Mining	1812	2525	2600	4212	4906	7259	9744	11693	11412	12425	11919	11968	13226	12676	11951	10328
	Construction				20	1760	8736	10177	10224	9187	911	259	--	--	--	--	--
	Transportation																
	Wholesale									30	42	42	57	57	57	57	57
	Manufacturing									105	260	260	307	307	307	307	307
ALASKA TOTAL	Mining	2042	3450	3985	6437	7906	10870	14031	17515	19351	21699	22841	22349	24261	24158	21733	20327
	Construction	--	--	120	2685	8813	21766	27676	23469	19085	6617	2616	929	283			
	Transportation								366	366	1077	1077	1586	1586	1586	1586	1586
	Wholesale						40	40	80	146	216	276	349	349	361	357	353
	Manufacturing								304	939	1258	1258	1654	1654	1754	1754	1754

Exhibit B-18-2

Exhibit B-19

Geographic Distribution of Induced and Secondary Employment—ANCHORAGE

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	100											
Retail Trade	100											
Services	100											
FIRE*	100											
Transportation	100											
Construction	100											
State and Local Government	100											

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* Finance, Insurance, Real Estate.

Exhibit B-20

Geographic Distribution of Induced and Secondary Employment—BARROW

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.40				.40							.20
Retail Trade	.20	.60			.20							—
Services	.10	.60			.10							.20
FIRE*	.20	.35			.20							.25
Transportation	.25	.50			.15							.10
Construction	.20	.60		.20								—
State and Local Government	.20	.60			.20							

- Finance, Insurance, Real Estate.

Exhibit B-21

Geographic Distribution of Induced and Secondary Employment – BRISTOL BAY

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.40		.40									.20
Retail Trade	.10		.70									.20
Services	.10		.70									.20
FIRE*	.10		.70									.20
Transportation	.20		.50		.10			.10				
Construction	.40		.70									.20
State and Local Government	.10		.70									.20

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* Finance, Insurance, Real Estate.

Geographic Distribution of Induced and Secondary Employment – CORDOVA

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.15			.40					.15		.15	.15
Retail Trade	.10			.70					.05		.10	—
Services	.10			.70					.05		.10	—
FIRE*	.20			.80								—
Transportation	.10			.50							.30	.10
Construction	.10			.70					.05		.10	.15
State and Local Government	.10			.70					.05		.10	—

- Finance, Insurance, Real Estate.

Exhibit B-22

Exhibit B-23

Geographic Distribution of Induced and Secondary Employment – FAIRBANKS

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.30				.60							.10
Retail Trade	.10				.85							.05
Services	.10				.85							.05
FIRE*	.10				.85							.05
Transportation	.30				.50						.10	.10
Construction	.10				.85							.05
State and Local Government	.10				.85							.05

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* Finance, Insurance, Real Estate

Geographic Distribution of Induced and Secondary Employment – KOBUK

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.10					—	.30				.15	.60
Retail Trade	.05					.60	.20					.15
Services	.05					.60	.20					.15
FIRE*	.05					.60	.20					.15
Transportation	.10					.50	.30					.10
Construction	.05					.60						.35
State and Local Government	.05					.60	.20					.15

• Finance, Insurance, Real Estate.

Exhibit B-24

Exhibit B-25

Geographic Distribution of Induced and Secondary Employment—NOME

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.10				.05		.40				.05	.40
Retail Trade	.05				.05		.80					.10
Services							.85				.05	—
FIRE*							.95				.05	—
Transportation	.20				.05		.70				.10	.05
Construction	.05						.90					.05
State and Local Government							.95					.05

• Finance, Insurance, Real Estate.

Exhibit B-26

Geographic Distribution of Induced and Secondary Employment— SEWARD

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.40							.40				.20
Retail Trade	.20							.80				—
Services	.10							.90				—
FIRE*								1,00				—
Transportation	.20							.70			.05	.05
Construction	.05							.90				.05
State and Local Government	.05							.90				.05

* Finance, Insurance, Real Estate.

Exhibit B-27

Geographic Distribution of Induced and Secondary Employment – SKAGWAY–YAKUTAT

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade											.60	.40
Retail Trade											.90	.10
Services											.90	.10
FIRE*											.90	.10
Transportation											.70	.30
Construction											.90	.10
State and Local Government					.40						.60	—

* Finance, Insurance, Real Estate.

Exhibit B-28

Geographic Distribution of Induced and Secondary Employment— VALDEZ

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.40							.10	.30			.20
Retail Trade	.10							.95	.25			.10
Services	.05								.90			.05
FIRE*									.95			.05
Transportation	.30							.10	.60			.10
Construction	.10							.10	.80			—
State and Local Government	.05				.20				.60			.15

* Finance, Insurance, Real Estate.

Geographic Distribution of Induced and Secondary Employment— YUKON

% of Induced Employment

Industry	Anchorage	Barrow	Bristol Bay	Cordova	Fairbanks	Kobuk	Nome	Seward	Valdez	Yukon	Skagway Yakutat	Other
Wholesale Trade	.40				.60							—
Retail Trade	.25				.45					.20		.10
Services	.05				.30					.60		.05
FIRE*					.60					.30		.10
Transportation	.25				.25					.50		—
Construction	.20				.20					.55		.05
State and Local Government	.10				.40					.30		.20

* Finance, Insurance, Real Estate.

Exhibit B-29

ENVIRONMENTAL IMPACT METHODOLOGY

Of necessity, the overall methodology to measure the environmental impacts of the development and facilities assumptions was geared to each of the three major impact areas - air, water, and land. Consequently, each of the resulting methodologies is detailed in turn in this appendix.

A - AIR POLLUTION METHODOLOGY

In accordance with the study's objectives, the methodology for estimating impacts of oil and gas development on the quality of air in Alaska focused on projecting these impacts in discrete areas, or impact sites, that are expected to experience secondary and induced economic activity. Given this guideline, we developed and used a methodology that would be both responsive to this requirement and productive in terms of accurate, meaningful results.

DEVELOPING THE METHODOLOGY

Ideally, air pollution is measured in terms of concentrations of a particular contaminant in the ambient environment.* These concentrations come about as a result of a complex interaction of pollutant emissions (also called loadings or residuals), topography, climatic conditions, and the passage of time. To reflect adequately all of these interacting parameters usually requires development of an atmospheric dispersion model, which is a mathematical description of these factors on a local basis. However, since such a model was beyond the scope of this study, it was necessary to adopt an approach that focused on changes in air pollution emissions and their likely effects on current ambient air quality.

Using this approach, we identified four possible situations:

- Situation 1: Current air pollution concentrations are above air quality standards, and projected pollution emissions are above current emission levels. In this case, we could say with reasonable confidence that the area would continue to not meet air quality standards.

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* Concentration would usually be measured in terms of weight of contamination per unit volume of air (e.g., grams per cubic meter) or weight of contaminant per weight of air (e.g., parts per million). Emissions are measured in weight per unit time (e.g., tons per year).

- Situation 2: Current air pollution concentrations are below air quality standards and projected pollution emissions are below current emission levels. In this case, we could say with reasonable confidence that the area would continue to meet air quality standards.

- Situation 3: Current air pollution concentrations are above air quality standards but projected emissions are expected to be below current emission levels. In this case, it is impossible to determine whether or not air quality will improve to meet air quality standards, unless the magnitude of the change is substantial.

- Situation 4: Current air pollution concentrations are below air quality standards but projected emissions are expected to exceed current levels. In this case, it is also impossible to determine whether or not air quality will degrade to the point air quality standards are not met, unless the magnitude of the change is substantial.

USING THE METHODOLOGY

To carry out this analytic approach, we first gathered data on current ambient air quality, ambient air standards, and current pollutant emissions; on the basis of these data, we then developed projections of future pollutant emissions.

Gathering Required Data

- Current ambient concentrations. Estimates of Alaska ambient air quality were based on Environmental Protection Agency (EPA) 1973 data provided by the agency's National Aerometric Data Bank. Concentrations of particulates, sulfur oxide (SO_x), nitrous oxide (NO_x), carbon monoxide (CO), and hydrocarbon (HC) were compared with State Air Pollution Control Regulations to determine whether current air quality complied with present standards. Those areas in which concentrations exceeded standards were highlighted.

- Current ambient air quality. Current standards for five parameters - particulates, SO_x, NO_x, HC, and CO - were obtained from the State Ambient Air Quality Standards. (See Exhibit C-1.)

- Current pollutant emissions. Based on the EPA's National Emissions Data System for Alaska, loadings of particulates, oxides of sulfur, oxides of nitrogen, hydrocarbons, and carbon monoxide from point and area source polluters were documented for each election district.*

Projecting Future Emissions

Utilizing these current emission data as well as projected population and economic growth for each of our impact sites, estimates of future emissions were developed for the years 1978, 1980, and 1990, by emissions sector, as follows:

- Residential. Primary sources of pollutant emissions in the residential sector are home heating devices - i.e., units used for space and water heating. To project air pollutant emissions from these residential sources, we identified current level of emissions and current number of housing units in each election district. (See Exhibit C-2.) We then calculated average emissions per housing unit. (See Exhibit C-3.) These per unit emissions figures were multiplied by the number of housing units predicted by the economic methodology, to yield total future emissions per year.

- Commercial-institutional. A technique similar to that used in the residential emissions projection was used to forecast emissions from commercial-institutional sources, since both categories have similar emissions characteristics. However, it was felt that total employment in the trade, services, and government sectors would represent the best indicator of activity in this sector. Exhibit C-4 shows pollutant emissions per employee in each election district, while Exhibit C-5 shows the total emissions from the commercial-institutional sector by election district.

- Industrial. For purposes of this study, industry was divided into primary oil and gas-related industry (e.g., gas processing), and all other industry (e.g., total combined fuel combustion and industrial process).

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* The most recent available data for both stationary and mobile sources were recorded in 1972-1973. Data are available for combustion, industrial processes, transportation, solid waste disposal, and miscellaneous sources. In addition, the National Emissions Data System provides an annual statistical summary for each election district, which includes, for example, units of fuel consumed for combustion by sector, gallons of fuel types consumed by transportation vehicle category, and solid waste tonnage burned by sector. We have correlated these statistics with emission data to project emissions for each sector.

- Primary oil and gas-related industry.
  - Refinery: No refineries were considered in this study.
  - Gas processing*: Pollutant loadings were estimated for each relevant process in a facility of 500 million cubic feet per day capacity**, as shown in Table 1, below. A factor of 10 percent was considered for shutdown of operations.

Table 1

Gas Processing Emissions

Emissions Tons/Plant Year

	Partic.	SO_x	NO_x*	HC	CO
Particulates					
H_2S Removal	5.5	0.2	36.5	12.0	0.1
NGL Separation	52.0	1.7	343.0	115.0	1.1
Liquefaction (LNG)	0.0	0.0	40,275.0	0.0	0.0
LPG Trucks	44.7	93.1	10,268.3	126.8	772.0
Total	102.2	95.0	50,922.8	253.8	773.2
10% Shutdown	10.2	9.5	5092.3	25.4	77.3
	92.0	85.5	45,830.5	228.4	695.9

* Significant because natural gas is used as the plant fuel.

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* Includes gas processing plants and, where applicable, liquefaction facilities.

** Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use, Table 25, Hittmann Associates, Inc., September 1973.

The total number of plants in each category (refinery and gas processing) under each scenario (allowing for size variance) was multiplied by emissions per standard plant to project primary related industry pollutant loadings.

- All other industries. Pollutant emissions from other industrial sources arise from both fuel combustion and process emissions. To project future emissions from these sources, we used a methodology analogous to that used for the residential and the commercial-institutional analyses. Specifically, current emissions per industrial employee were calculated. This figure, times the projected number of industrial employees in each election district, was used to determine all other industrial emissions. Exhibit C-6 shows pollutant emissions per employee, while Exhibit C-7 shows the total emissions from the industrial sector, by election district.

- Transportation
  - Diesel land vehicles (e.g., heavy, off highway, and rail). To project future emissions from diesel land vehicles, we calculated emissions per employee, and the expected number of employees in the trade, services, and government sectors for each election district, and multiplied that number by the amount of emissions per employee. Exhibit C-8 shows emissions per employee, while Exhibit C-9 displays the total emissions from diesel land vehicles, by election district.
  - Other transportation sources, including gasoline land vehicles (e.g., light, heavy, off highway, rail), aircraft (e.g., military, civilian), and vessels (e.g., diesel fuel, gasoline). To project potential emissions from other transportation sources, a methodology similar to the one described for diesel fuel vehicles was used; however, the emission projections were based on current emissions per capita and projected population in each election district. Exhibit C-10 shows pollutant emission per capita for other transportation sources. Exhibit C-11 indicates total emissions from this source.

- *Solid waste*. 1972-1973 emissions from solid waste disposal activities resulted primarily from open burning and on-site incineration at residential, commercial, and industrial locations; emissions from municipal incineration were recorded only for Fairbanks. The 1973 Alaska Solid Waste Management Regulations state, as a major goal, that "solid waste shall be collected, processed and disposed in order to control, prevent and abate pollution of the air." However, the law also specifies that:

    - Single-family and duplex residences are allowed to dispose of solid waste generated on-premise.

    - Incinerator facilities having a total rated capacity of less than 200 pounds of solid waste per hour are allowed to operate without a permit.

    - Particulate matter emitted from *all* incinerators installed *on* or *after* July 1, 1972, may not exceed, on the basis of a cubic foot of exhaust gas: (a) 0.3 grains for incinerators less than or equal to 200 pounds per hour rated capacity; (b) 0.2 grains for incinerators larger than 200 but equal to or less than 1,000 pounds per hour rated capacity; and (c) 0.1 grains for incinerators larger than 1,000 pounds per hour rated capacity.

    - Open burning of a landfill is prohibited.

  One can conclude from these regulations that emissions from single-family and duplexes and from pre-1972 incinerators will continue. However, although the effect of the tighter emission limitations on *new* incinerators is unknown, we feel it will result in lower emission levels. Also, as pre-1972 incinerators become obsolete and are abandoned, emissions should be further reduced. (However, this could be counterbalanced by more incinerators in single- and 2-family homes.) Considering all these effects, we estimated future emissions would remain at roughly current emissions levels. (See Exhibit C-12.)

- *Electric utilities*. To project emissions from electric utilities, the last major source of air pollutant emissions, a 3-step process was employed. First, the fuel most likely to be used by electric utilities was identified. This involved analyzing current fuel use and capacity (e.g., coal fired), as well as determining the likelihood of oil and gas becoming available as fuels. Second, average electricity use per capita was multiplied by total number of residents, to obtain total generation. Finally, the emissions from this generation were calculated, using the emission rates of Exhibit C-13.

B - WATER POLLUTION METHODOLOGY

To estimate the impacts of additional Alaskan oil and gas development on water quality, we developed and applied a methodology that focused on the major potential sources of water pollution - i.e., primary related oil and gas industries; other industries; and the public, especially given the projected population growth.

DEVELOPING THE METHODOLOGY

In formulating our methodology, we examined various techniques of forecasting water quality impacts. From this examination, we concluded that an exact, quantitative approach was not feasible within the scope of this study because current water quality data (e.g., on color, pH levels, and dissolved oxygen levels) were not easily related to point source emissions data (e.g., tons of effluent per year); in addition, data on location and relative size of point source emissions in Alaska are scarce. Moreover, projections of future water quality in a particular watercourse depends on the timing, location, and size of emission sources, which would have necessitated a detailed flow model.

In view of these problems, we designed a methodology that allowed a qualitative determination of water quality impacts. This methodology was based on the identification of current water quality at each of the impact sites, and a judgment assessment of whether or not future water quality would exceed or drop below standards.

USING THE METHODOLOGY

Implementation of the methodology required: (1) collecting relative data; and (2) projecting future loadings.

Collecting Relevant Data

The water quality obtained from the Environmental Protection Agency's Region X Data Systems Branch represented recordings from both EPA and USGS monitoring stations at sites throughout the state. Based on these EPA data, we composed water resource tables indicating the measurements of nine parameters at stations adjacent to those locations chosen for review in this study. (See Exhibit C-14 for an example of the data.) Because all stations did not record the same number of parameters, certain significant parameters were selected to provide comparability (see Exhibit C-15) for a description of the parameters selected). Furthermore, comparisons were made between the water quality standards of the State of Alaska, listed in Exhibit C-16, and the actual parameter recordings at each of the stations. Those parameter measurements that appeared to be in excess of state standards were so indicated on the tables.

Projecting Future Effluents

As noted earlier, it was not feasible to assess the changes in water quality resulting from population and subsequent industrial growth through a quantitative impact analysis. Rather, we were able to analyze only the current quality of the water resources in each impact area, and then to assess qualitatively the likely impact of additional effluents from community and industrial gorwth. Therefore, we used an analysis similar to that described for air pollution. For example, although current water quality within an area may be in compliance with state standards, projected population and industrial growth might cause a significant increase in effluents, which, in turn, would cause changes in the levels of parameter concentrations. If, on the other hand, projected growth were not expected to be significant, additional water pollution loadings might not affect the level of water quality significantly.

As we indicated at the outset of this section, water quality will probably be most affected by the activities of primary related oil and gas industries and other industries; an increase in the state's population could also affect water quality.

- Primary related oil and gas industrial activities. According to the EPA's 1974 National Water Quality Inventory, Alaska has a total of 23 petroleum-related industrial surface water dischargers, as shown below in Table 2.

Table 2

Oil and Gas Industry Water Dischargers

Industry Segment	Major Discharges	Minor Discharges
Oil and Gas Mining	7	11
Petroleum and Coal Products	2	1
Misc. Transportation (pipelines)	2	-
Totals	11	12

Further oil and gas development will involve construction of new facilities, which will discharge additional wastes into surface receiving waters. To determine what level these additional wastes might reach, we estimated the number of minor and major petroleum-related industrial dischargers to be developed under each scenario.

In addition to producing additional wastes, further exploration and development drilling will produce, and necessitate the disposal of, mud and cuttings.

This "refuse dumping" will influence to some degree, the quality of marine life, as will oil spills, which, of course, are always a possibility. Refinery effluents had to be considered also. However, the available data on water pollution loadings from refineries, with the exception of suspended solids, did not fit the water quality parameters chosen for the study. Nevertheless, estimates of annual loadings (in tons) from a 200,000 barrel per day refinery were developed, as shown in Table 3.

Table 3

Assumed Water Pollution Loadings for a Sample Refinery
(Tons per Year)

BOD		COD		Suspended Solids		Phenol		Sulfide		Ammonia	
BA*	BP**	BA	BP	BA	BP	BA	BP	BA	BP	BA	BP
46	548	365	2281	46	548	0	18	0	9	9	180

* Best available (advanced) treatment.

** Best practical (secondary) treatment.

Source: RPA estimates, based on industry sources, the Roy Weston report, and Radian Corporation technical reports on refinery effluents.

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* Approved by the Alaska Department of Environmental Conservation; where interstate waters would be affected, this approval would have to be concurred in by the EPA.

Gas processing facility effluents were also considered. However, available data indicated the water quality impacts of gas processing facilities are very small.*

- Other industry activities. EPA's 1974 National Water Quality Inventory cites a total of 108 minor and 16 major discharging facilities (point sources) in Alaska for industries other than oil or gas. (See Table 4.) To determine what water quality impacts might occur in the future from this source, we estimated the incremental increase in the number of these facilities in each category under each scenario.

Table 4

Major Nonoil and Gas Industrial Water Pollution Discharges

Industry	Discharging Facility	
	Major	Minor
Meat Products		2
Seafood Products	14	78
Lumber and Wood Products		3
Paper and Allied Products	2	
Chemicals and Allied Products		2
Electric and Gas Utilities		8
Water and Sanitary Services		1
Wholesale and Retail Trade		4
Government		1
Nonclassifiable		9
Totals	16	108

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* See, for example, Environmental Impacts, Efficiency, and Costs of Energy Supply and End Use, Hittman Associates, 1973.

- Population growth. Alaska currently operates 38 municipal waste treatment facilities to process residential waste. These facilities have been subdivided according to level of treatment, as follows: none - 4; primary - 8; secondary, adequate - 0; secondary, inadequate - 1; secondary, unclassified - 25; and tertiary - 0. New residents will, of course, create a need for additional municipal waste treatment plants, which will have to comply with the treatment specifications of the Federal Water Pollution Control Act of 1972. Therefore, we developed an estimate of how many additional plants would be needed, based on population growth estimates.

C - LAND USE METHODOLOGY

The methodology used to measure the land impacts of oil and gas development in Alaska consisted of determining the present amount developed land in each impact area; estimating the amount of land in each area that can be developed without constraint; and projecting the acreage required for development in each area under each scenario. Finally, we determined whether sufficient land would be available at each site for the land requirements of each development alternative. In the two sections that follow, we explain this approach in terms of its development and use.

DEVELOPING THE METHODOLOGY

In analyzing land use impacts of oil and gas development, we classified land use into two categories:

- Developed land. Developed land is all land currently in use or being developed, including:
    - Residential land - single-family houses and mobile homes, multifamily houses and apartments, boarding houses and dormitories
    - Commercial and industrial land - retail and wholesale establishments, warehouses, office and other service buildings, land used for light and heavy manufacturing, and oil- and gas-related activities
    - Other developed land - public and quasi-public institutional buildings (e.g., schools, churches, hospitals), transportation (e.g., railroads, streets, airports, highways), and public open spaces (e.g., urban parks and recreational areas), excluding national and state park areas.

- *Undeveloped land.* Although undeveloped land clearly implies land that is not, as yet, developed, it is *not* synonymous with *all* land available for development. Certain constraints render various areas inappropriate for development - e.g.:
  - Land unavailable because of existing use, planned use, or environmental constraints
    - Existing and planned national, state, and local parks, reserves, and wildlife refuges; and government, utility, and institutionally owned land are considered unavailable. Where known, planned recreation and conservation areas, including outstanding beauty spots, are also considered unavailable.
    - Areas of impoundment or zoned areas adverse to industrial use are considered unavailable.
    - All wetlands are considered unsuitable because of their unique wildlife supporting capacity and extreme ecological vulnerability. Principal elements of water resource systems, rivers and lakes, river banks to 300 feet, selected watersheds, aquifers, aquifer recharge areas, and floodplains are also considered unsuitable for development. As these areas are difficult to quantify, only a rough estimate of their extent was made.
  - Land unsuitable because of location constraints
    - Water supply land should be reserved for municipal drinking supply and private withdrawals, and is inadequate for industry.
    - Land inaccessible to transportation networks is considered unsuitable.

Subtracting these developable but unavailable lands from the undeveloped land total produces, of course, the actual amount of *undeveloped but developable* land.

USING THE METHODOLOGY

Implementing this approach involved two steps: (1) collecting necessary data; and (2) developing land-use projections.

Gathering Required Data

A land use survey was sent to the office of the city manager of each location in which potential impacts could occur. The survey was sent also to the planning departments of the various boroughs incorporating the impact locations, and to the Alaska Department of Natural Resources, Division of Lands, which conducts surveys on similar land classifications. Data on current land use, as well as the amount of undeveloped land, were available for each impact area. For example, the survey completed by the land officer in Valdez is presented in Exhibit C-17. From the information that was collected, we prepared maps, indicating areas of present development as well as areas suitable for potential location of industrial and other activities. Where no data were provided on suitability of land for development, reasonable estimates were made on the basis of geographical and environmental considerations.

Developing Projections

Projections were made for 1980, 1985, and 1990 of the acreage required for each development scenario for:

Primary related industries. Onshore oil and gas field acreage, where adjacent to an impact locality, was derived for each development alternative. Land requirement ratios (acreage required per specified unit capacity; see Exhibit C-18) were developed for each primary activity, considering required production capability, storage capacity, and expansion needs.

Other industrial and commercial activities. To project other industrial and commercial land requirements, we chose commercial and industrial employment as a measure of activity, using current land required per employee as a basis for our calculations. (See Exhibit C-19.)

Residential construction. Residential construction land requirements were projected by: (1) translating population forecasts obtained through the economic methodology into numbers of housing units needed; and (2) assuming each projected housing unit would require the same amount of land as current housing units. This total figure represented the upper limit of the amount of residential land needed. However, to establish a range of required residential land requirements, we assumed total current land requirements as the lower limit of total land requirements. The current ratios of land per residential housing unit for each impact area are shown in Exhibit C-20.

Other developed land. A straight-line projection for other developed land use was made, based on current other developed land use per capita. (See Exhibit C-21.) We believed this was the most reasonable assumption because many intangibles affect the land set aside by communities for recreational and other public or quasi-public uses.

Finally, Exhibit C-22 is an example of the land use summary we used. Two summaries were prepared for each location for each development scenario: one indicates acreage requirements; the other indicates percentage of total land required for each land classification category.

Exhibit C-1

ALASKAN AMBIENT AIR QUALITY STANDARDS

Pollutant	Annual Geometric/ Arithmetic Mean	Average Maximum Not To Be Exceeded More Than Once Per Year
Particulates	60 microgr/m^3	150 microgr/m^3 (24 hour period)
SO_x	60 microgr/m^3	260 microgr/m^3 (24 hour period)
NO_x	100 microgr/m^3	1300 microgr/m^3 (3 hour period)
HC		160 microgr/m^3 (3 hour period)
CO		10 milligr/m^3 (8 hour period) 40 milligr/m^3 (1 hour period)

Source: *Alaska Air Pollution Control Regulations*, Alaska Administrative Code, Title 18, Environmental Conservation, Chapter 50, Air Quality Control, effective May 1972, amended November 1972.

Exhibit C-2

AVERAGE RESIDENTIAL EMISSIONS, 1972-1973

Election District	Current Number of Occupied Housing Units	Pollutants Emitted per Housing Unit (Tons)				
		Partic.	SO_x	NO_x	HC_x	CO_x
Anchorage	42,110	.003	.006	.008	.001	.003
Barrow	358	.011	.008	.078	.008	.020
Bethel	1,173	.031	.019	.017	.021	.022
Cordova-McCarthy	602	.005	.015	.007	.002	.003
Fairbanks	14,212	.026	.026	.009	.022	.090
Kobuk	615	.081	.028	.039	.062	.063
Nome	934	.037	.022	.020	.027	.028
Seward	733	.012	.014	.018	.008	.010
Valdez-Chitina-Whittier	938	.004	.011	.006	.001	.002
Yakutat-Skagway	728	.011	.012	.008	.007	.007

Exhibit C-3

ANNUAL PER UNIT RESIDENTIAL POLLUTANT LOADINGS BY ELECTION DISTRICT, 1972-1973

(Tons)

Election District	Pollutant					Current Number of Housing Units
	Partic.	SO_x	NO_x	HC	CO	
Anchorage	128	246	343	61	123	42,110
Barrow	4	3	28	3	7	358
Bethel	36	22	20	25	26	1,173
Cordova-McCarthy	3	9	4	1	2	602
Fairbanks	364	373	128	317	1,274	14,212
Kobuk	50	17	24	38	39	615
Nome	35	21	19	25	26	934
Seward	9	10	13	6	7	733
Valdez-Chitina-Whittier	4	10	6	1	2	938
Yakutat-Skagway	8	9	6	5	5	728

Source: Environmental Protection Agency's National Emissions Data System.

Exhibit C-4

ANNUAL COMMERCIAL POLLUTANTS PER EMPLOYEE, 1972-1973

Election District	Pollutant				
	Partic.	SO_x	NO_x	HC	CO
Anchorage	.009	.015	.049	.003	.006
Barrow	.012	.022	.046	.003	.003
Bethel	.007	.009	.014	.018	.001
Cordova-McCarthy	.008	.023	.037	.003	.003
Fairbanks	.095	.061	.057	.005	.014
Kobuk	.106	.035	.032	.004	.013
Nome	.008	.014	.031	.002	.002
Seward	.012	.020	.078	.004	.010
Valdez-Chitina-Whittier	.006	.017	.022	.001	.001
Yakutat-Skagway	.004	.006	.014	.001	.001

Exhibit C-5

TOTAL POLLUTANTS FROM COMMERCIAL-INSTITUTIONAL SOURCES PER ELECTION DISTRICT, 1972-1973

(Ton)

Election District	Pollutant					Employment Trade, Govt., Services
	Partic.	SO_x	NO_x	HC	CO	
Anchorage	309	535	1,776	102	201	36,059
Barrow	8	15	31	2	2	677
Bethel	12	15	22	29	2	1,605
Cordova-McCarthy	3	8	13	1	1	355
Fairbanks	1,167	750	698	64	168	12,228
Kobuk	88	29	26	3	11	825
Nome	8	15	32	2	2	1,035
Seward	6	10	40	2	5	512
Valdez-Chitina-Whittier	4	12	15	1	1	693
Yakutat-Skagway	3	5	11	1	1	778

Source: Environmental Protection Agency's National Emissions Data System.

Exhibit C-6

ANNUAL INDUSTRIAL EMISSIONS PER EMPLOYEE, 1972-1973

Election District	Pollutant				
	Partic.	SO_x	NO_x	HC	CO
Anchorage*	.518	1.778	1.848	.031	.073
Barrow**					
Bethel**	.627				
Cordova	.160	1.863	.531	.023	.023
Fairbanks	23.532	4.976	9.624	.640	1.276
Kobuk**	.167	.333	.667		.083
Nome**	71.795				
Seward					
Valdez**	.200	.300	.700		
Yakutat-** Skagway	.034				

* A weighted average for Anchorage-Cordova was used.

** Either there is no current industry or data were withheld to avoid disclosures.

Exhibit C-7

ANNUAL INDUSTRIAL EMISSIONS PER ELECTION DISTRICT, 1972-1973

Election District*	Pollutants						Employment (Manufacturing)
	Particulates						
	Combustion	Total (Including Process)	SO_x	NO_x	HC	CO	
Anchorage	234	674	2,311	2,402	40	95	1,300
Barrow							0
Bethel		32					51
Cordova-McCarthy	28	28	326	93	4	4	175
Fairbanks	1,778	5,883	1,244	2,406	160	319	250
Kobuk	2	2	4	8	--	1	12
Nome		2,800					39
Seward							75
Valdez-Chitina-Whittier	2	2	3	7	--	--	10
Yakutat-Sakgway		10					296

* For some election districts there is no current industry or data were withheld to avoid disclosures.

Source: Environmental Protection Agency's National Emissions Data System.

Exhibit C-8

ANNUAL EMISSIONS FROM DIESEL LAND VEHICLES PER EMPLOYEE, 1972-1973

Election District	Pollutant				
	Partic.	SO_x	NO_x	HC	CO
Anchorage	.006	.009	.076	.013	.030
Barrow	.006	.006	.068	.007	.021
Bethel	.006	.006	.067	.007	.019
Cordova	.008	.008	.082	.008	.025
Fairbanks	.013	.023	.175	.037	.066
Kobuk	.007	.007	.081	.008	.024
Nome	.008	.008	.084	.009	.024
Seward	.041	.086	.578	.139	.199
Valdez-Chitina-Whittier	.006	.006	.072	.007	.022
Yakutat-Skagway	.004	.004	.042	.004	.013

Exhibit C-9

TOTAL ANNUAL EMISSIONS FROM DIESEL LAND VEHICLES, 1972-1973

Election District	Pollutant					Employment (Trade, Govt., Services)
	Partic.	SO_x	NO_x	HC	CO	
Anchorage	220	317	2742	477	1073	36,059
Barrow	4	4	46	5	14	677
Bethel	9	9	107	11	31	1,605
Cordova	3	3	29	3	9	355
Fairbanks	159	287	2142	454	804	12,228
Kobuk	6	6	67	7	20	825
Nome	8	8	87	9	25	1,035
Seward	21	44	296	71	102	512
Valdez-Chitina-Whittier	4	4	50	5	15	693
Yakutat-Skagway	3	3	33	3	10	778

Source: Environmental Protection Agency's National Emissions Data System.

Exhibit C-10

ANNUAL EMISSIONS PER CAPITA FROM TRANSPORTATION SOURCES 1972-1973

(Excluding Diesel Land Vehicles)

Election District	Pollutant				
	Partic.	SO_x	NO_x	HC	CO
Anchorage	.007	.002	.035	.076	.565
Barrow	.002	.001	.018	.049	.525
Bethel	.002	.001	.016	.042	.456
Cordova	.004	.003	.031	.057	.483
Fairbanks	.005	.002	.026	.062	.482
Kobuk	.003	.001	.019	.049	.478
Nome	.005	.003	.035	.085	.623
Seward	.003	.002	.030	.048	.397
Valdez-Chitina-Whittier	.006	.005	.056	.074	.506
Yakutat-Skagway	.003	.001	.019	.038	.335

Exhibit C-11

TOTAL ANNUAL EMISSIONS FROM TRANSPORTATION SOURCES, 1972-1973

(Excluding Diesel Land Vehicles)

Election District	Pollutant					Population
	Partic.	SO_x	NO_x	HC	CO	
Anchorage	1,033	340	5,173	11,437	84,736	149,911
Barrow	4	2	38	100	1,082	2,059
Bethel	10	5	101	260	2,826	6,192
Cordova	7	5	58	108	913	1,889
Fairbanks	308	94	1,470	3,512	27,152	56,278
Kobuk	10	3	63	164	1,603	3,351
Nome	21	13	154	377	2,768	4,445
Seward	8	4	71	115	943	2,376
Valdez-Chitina-Whittier	18	15	178	232	1,594	3,151
Yakutat-Skagway	7	2	49	98	866	2,586

Source: Environmental Protection Agency's National Emissions Data System.

Exhibit C-12

TOTAL ANNUAL EMISSIONS FROM RESIDENTIAL SOLID WASTE DISPOSAL, 1972-1973

(Tons Per Year)

Election District	Pollutant					Population
	Partic.	SO_x	NO_x	HC	CO	
Anchorage*	NA	NA	NA	NA	NA	149,911
Barrow	22	1	7	43	125	2,059
Bethel	24	1	9	45	128	6,192
Cordova	6	-	2	11	30	1,889
Fairbanks	359	20	118	718	2,057	56,278
Kobuk	34	2	11	69	196	3,351
Nome	46	3	15	93	266	4,445
Seward*	NA	NA	NA	NA	NA	2,376
Valdez-Chitina-Whittier	9	1	3	17	47	3,151
Yakutat-Skagway	2	-	-	6	18	2,586

* Data were unavailable for Anchorage or Seward; therefore, the per capita emissions estimated for Fairbanks will be used for these two election districts.

Source: Environmental Protection Agency's National Emission Data System.

Exhibit C-13

TOTAL ANNUAL EMISSIONS FOR ELECTRIC POWER GENERATION, 1972-1973

(Tons / 10^{12} Btu)

Fuel	Pollutant				
	Partic.	SO_x	NO_x	HC_x	CO_x
Oil	27.2	320.0	357.0	6.8	.1
Gas	7.3	.3	191.0	2.0	.1
Coal	43.9	323.0	394.0	6.6	21.9
(tons / 10^8 kwh)					
Oil	79.7	937.6	1046.0	19.9	.3
Gas	21.4	.9	559.6	5.86	.6
Coal	128.6	946.4	1154.4	19.3	64.2

10^{12} Btu = 2.93 x 10^8 Kwh

Source: *Environmental Impacts, Efficiency, and Cost of Energy Supply and End Use*, Table 26, Hittman Associates.

Site: Seward

WATER QUALITY SUMMARY

Station	Temp (°C)	Stream Flow (Cubic Feet/Second)	Turbidity (Jackson Turbidity Units)	Color (Units)	Conductivity (Micromho)	Dissolved Oxygen (mg/l)	pH (Standard Units)	Dissolved Solids		Suspended Sediment	
								Sum (mg/l)	Tons/Day	Concentration (mg/l)	Discharge (Tons/Day)
Bear Cr.	2.0 (1968)	4.45 (1968)		0 (1968)	142.0 (1968)		7.7 (1968)	80.0 (1968)	.96 (1968)		
Lost Cr.	4.67 (1950-71)	51.07 (1950-71)		5.0 (1950-71)	63.33 (1950-71)		7.17 (1950-71)	43.0 (1971)	.91 (1971)		
Spruce Cr.	3.53 (1968-72)	80.36 (1968-72)		2.5 (1968-70)	61.81 (1968-72)		7.32 (1968-71)	35.94 (1968-70)	6.34 (1968-70)	1.77 (1968-72)	.52 (1968-72)
Snow R.	5.5 (1950-64)	429.23 (1950-62)		6.37 (1950-58)	80.87 (1950-64)		6.93 (1950-58)	50.73 (1950-58)	22.4 (1950-58)	289.95 (1959-64)	1066.56 (1959-62)
Resurrection R.	4.47 (1952-68)	1382.13 (1959-68)		4.64 (1952-68)	125.97 (1952-68)		7.27 (1952-68)	74.65 (1965-68)	160.0 (1952-68)	177.41 (1959-68)	1872.12 (1959-68)
Resurrection Bay	5.57 (1965-67)	1833.56 (1965-67)			83.0 (1967)		7.2 (1967)	49.0 (1967)		210.82 (1965-67)	2315.92 (1965-67)

Exhibit C-14

WATER QUALITY PARAMETERS

Description	Significance
May be caused by a wide variety of suspended materials - rock particles produced by the grinding action of a glacier; topsoil washed to receiving streams; and organic and inorganic domestic and industrial wastewater added to rivers.	Measurement of sanitary significance - consumers are wary of high-turbidity, cloudy waters; filtration is more difficult and costly with increased turbidity; and the killing of pathogenic organisms by disinfectant may be considerably hindered.
Results from the presence of colloidal vegetable and organic extracts; industrial wastes resistant to biological destruction; and pulping and textile wastewater disposal into natural watercourses.	Most colored waters are not considered toxic. However, consumers are reluctant to drink water not aesthetically acceptable.
An expression of the intensity of the acid or alkaline condition of a solution and the hydrogen-ion activity. Industrial wastes contain organic and mineral acids, the latter resulting primarily from the metallurgical industry and abandoned mine drainage.	A factor which must be considered in chemical coagulation, disinfection, and corrosion control.
Determines whether biological changes are brought about by aerobic or anaerobic organisms - the former produce innocuous and the latter obnoxious end products. Favorable DO levels will support fish and other aquatic organisms in a healthy condition.	Measurement is the basis of the BOD test, thus the foundation of the most important determination used to evaluate the pollutional strength of sewages and industrial wastes.
Primarily inorganic salts, small amounts of organic matters, and dissolved gases. Increased levels from discharge of oil fields, diversion of streams, and deepening of channels.	Suitability of water for domestic use is indicated. Waters with high solids content can be disruptive to human disgestion.

Exhibit C-15-1

Exhibit C-15-2

WATER QUALITY PARAMETERS
(continued)

Parameter	Description	Significance
Suspended Sediment	Undissolved colloidal and suspended matter. Sludges, silt, mining gravel from industrial operations may increase the load of finely divided, chemically inert materials carried by waters.	Causes turbidity and reduces light penetration, restricting photosynthetic activity of plants and animal's vision and feeding habits.
Stream Flow	Measurement of the rate of discharge, representing the speed with which a volume of 1 cubic foot passes a given point during 1 second.	Indicates the discharge that occurs in a natural channel.
Temperature	Increases result from waste heat disposal, impounding of river waters, reduction of stream flow, and removal of forest canopies.	Changes in temperature decrease distribution and abundance of aquatic animals.

Exhibit C-16

ALASKA WATER QUALITY STANDARDS*

Parameter	Measurement
Temperature	Below 60° F
Stream Flow	NA
Turbidity	Less than 5 JTU
Color	True color less than 15 color units
Conductivity	NA
Dissolved Oxygen	Greater than 75% saturation or 5 mg/l
pH	Between 6.5 and 8.5
Dissolved Solids	Total dissolved solids from all sources may not exceed 500 mg/l
Suspended Sediment	Below normally detectable amounts

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* Alaska Water Quality Standards, Alaska Administrative Code, Title 18, Environmental Conservation, Chapter 70, effective October 1972. (For drinking, culinary, and food processing without the need for treatment other than simple disinfection or removal of naturally present impurities.)

Exhibit C-17

LAND USE SUMMARY VALDEZ (ACRES)

	Town Limits
Currently Developed Land	
Residential use: (single family houses, mobile homes, multi-family houses, apartments, boarding houses, dormitories)	206.5
Commercial and industrial use: (retail and wholesale establishments, warehouses, office buildings and other services, light and heavy manufacturing)	1,400
Other uses: (public and quasi-public institutional buildings (e.g., schools, churches, hospitals) transportation avenues (e.g., railroads, streets, highways and airports) public open spaces (e.g., urban parks and recreational areas)	215
Total Acreage	2,821.5*
Undeveloped Land	
Total	
Unavailable land due to environmental constraints:	
• existing and projected uses, planned federal, state and local parks, recreation and conservation areas, reserves and refuges, utility and institutionally owned lands	0
• zoning restrictions	0
• ecological constraints--wetlands and principal elements of water resources systems (e.g., rivers, lakes, watersheds, aquifers, floodplains)	0
Land unsuitable for development due to locational constraints such as:	
• water supply--should be reserved for municipal drinking supply and private withdrawals; inadequate for industry	0
• inaccessible to transportation networks	0
Total remaining developable land	12,500
Undeveloped land being planned	1,500
Total Land	16,800

(*Approximately 1000 acres currently being developed are scheduled to be complete during 1975.)

Exhibit C-18

LAND USE RATIOS FOR PRIMARY INDUSTRIES

Facility	Acreage of Plant	Storage Requirement
Refineries		
- 200 MBPD	1200	80
- 25 MBPD	170	10
Gas Processing Facility (500 million cubic feet/day)	10	-
LNG Facility		
- 1 billion cubic feet/day	400	(Included in plant acreage)
- 2 billion cubic feet/day	600	
Terminals	-	900

Source: CEQ and RPA, *OCS Oil and Gas - An Environmental Assessment*, April 1974, and El Paso Alaska Co., *Application for a Certificate of Public Convenience and Necessity*, March 1, 1975.

Exhibit C-19

INDUSTRIAL-COMMERCIAL LAND USE

Impact Area	Current Commercial And Industrial Acreage	Current Employment (Trade, Services, Government, Manufacturing)	Current Land Use Per Commercial and Industrial Employee (In Acres)
Anchorage (borough)	8,063	36,159	0.223
Barrow (city)	10	455	.022
Bethel (greater area)	320	640	0.500
Cordova	N.A.	695	-
Fairbanks (metropolitan area)	1,868	12,290	0.152
Kotzebue (city)	5	698	.007
Nome	625	867	0.721
Seward (city)	176	690	0.255
Valdez (city)	1,400	309	4.53
Yakutat (city)	20	45	0.444

Source: Community Profiles, Alaska Department of Economic Development, and discussion with city managers and local officials.

Exhibit C-20

RESIDENTIAL LAND USE

Impact Area	Current Residential Acreage	Current Number Of Housing Units	Current Land Use per Housing Unit (In Acres)
Anchorage (borough)	32,026	43,430	0.737
Barrow (city)	60	401	0.150
Bethel (greater area)	960	1,610	0.596
Cordova	N.A.	N.A.	N.A.
Fairbanks (metropolitan area)	2,554	12,590	0.203
Kotzebue (city)	435	311	1.399
Nome	4,910	523	9.388
Seward (city)	426	563	0.757
Valdez (city)	207	329	0.629
Yakutat (city)	50	68	0.735

Source: Community Profiles, Alaska Department of Economic Development, and discussion with city managers and local officials.

Exhibit C-21

OTHER DEVELOPED LAND-USE

Impact Area	Current Other Developed Land	Current Population	Current Other Developed Land Use (Acres per Capita)
Anchorage (borough)	9,648	154,610	.063
Barrow (city)	32	2,307	.014
Bethel (greater area)	1,280	8,500	0.151
Cordova	N.A.	N.A.	N.A.
Fairbanks (metropolitan area)	10,093	49,856	0.202
Kotzebue (city)	875	1,696	0.516
Nome	35	2,488	.014
Seward (city)	38	1,823	.021
Valdez (city)	215	1,016	0.194
Yakutat	40	240	0.167

Source: Discussion with city managers and local officials; community profiles prepared by Alaska Department of Economic Development.

Exhibit C-22

LAND USE SUMMARY BY

Development Scenario

By Location

Land Use Classification	Current Development	1980		1985		1990	
		Base Case	Devel. Scenario	Base Case	Devel. Scenario	Base Case	Devel. Scenario
Developed Land							
Commercial/ Industrial							
Primary							
Other Industrial and Commercial							
Residential							
Other Developed Land Projections							
Undeveloped Land							
Unavailable/ Unsuitable							

Source: Current development from discussion with city managers and local officials; RPA estimate.